ADICA CONSULTING, LLC
125 Windsor Dr., Suite 121
Oak Brook, IL 60523 USA
Website: www.adica.com
Telephone: (630) 571-2480
Facsimile: (630) 571-2481
US Toll Free: (866) OK ADICA

VOLUME I REPORT:

Economic Viability, Financing and Contracts for Renewable Energy Projects in CARRICOM

Findings, Recommendations, and Documentation

Edward Bodmer
Dr. Roland Clarke
Conrad Reddick

ADICA
CONSULTING

Preface

Many Caribbean countries have recognized the local and global environmental effects of the governmental and industrial policies related to energy practices. The CARICOM Secretariat's[1] Caribbean Renewable Energy Development Project (CREDP) is a visible and practical part of the regional commitment Caribbean nations have to environmental sustainability. This report represents part of the CREDP effort designed to provide practical technical assistance to utility companies, private developers of renewable resource projects, financiers of renewable ventures, and government agencies seeking to promote environmentally sustainable policies.

Our express objective in this project has been to avoid producing yet another study for the shelves of RET stakeholders. The problems and potential benefits of renewable energy technologies are very well documented. Rather than recounting general aspects of renewable technologies, this project seeks to facilitate the realization of renewable technology's benefits by providing technical assistance to stakeholders for projects by explaining how the development of renewable projects can reduce utility costs and electric bills; and by promoting equitable negotiation of contracts between developers and utility companies.

This report documents a number of tools developed by CARICOM to assist stakeholders in their efforts to develop and finance electricity generation facilities that use renewable resources. Our provision of technical assistance includes various databases, surveys, and software tools. In addition, template documents and information memoranda are developed to provide guidance for future developers of RET projects as they navigate the waters of the commercial financing process. A library of the research and reference materials we used is also provided.

Acknowledgements

The information collected through our surveys and interviews with regional developers is the product of cooperative and interactive development activities with CARICOM CREDP professionals. Information developed by previous CREDP consultants provided a foundation for many of the quantitative and development activities undertaken in this effort. Obtaining sensitive data from regional financial institutions and utilities would have been impossible without the advice, good offices and, when necessary, timely interventions of CREDP professionals and regional consultants. Their active participation was invaluable.

[1] References in this Report to CARICOM should be understood to mean the CARICOM Secretariat, unless the context clearly indicates the larger organization.

Among the individuals deserving specific mention are Ms. Cicely Cramer of CARICOM, who was instrumental in following-up on surveys and arranging teleconferences. Victor Poyotte of CARILEC, the association of Caribbean Electric Utilities, was generous with his time and advice, and he was instrumental in disseminating the utility survey instruments to the appropriate experts within regional utilities. Finally, even though our plan to make Ms. Enid Bissember a member of our consultancy team was unsuccessful, she generously assisted us in identifying and in contacting members of the Caribbean financial community in connection with our survey of financial institutions.

Organization of the Final Report

This Final Report is presented in three volumes for ease of reference and to facilitate selective reproduction and distribution of the included materials.

Volume I (Report) of the Final Report contains background information, the discussions of RET financing topics, an explication of the three prongs of our financial analysis (project financials, avoided costs, and rate impact), and the development of bases for our findings and recommendations. Those findings and recommendations are drawn from our analysis of the information, data, and materials gathered in the course of the project. The team of professionals contributing to this project interviewed financial and RET experts in the CARICOM region and in other areas of the world. Project finance, avoided cost, and corporate finance software was developed and implemented to represent specific characteristics of the Caribbean. We have created databases using utility information, resource assessments, and data from the CARICOM pipeline for the project finance, hourly avoided cost, and rate impact models. Our work has also included development of detailed surveys that have been delivered to utility companies and financiers in the Caribbean. Finally, we reviewed contracts related to financing from countries where RET projects have been more widely developed, as well as financing instruments from the region.

Volume II (Templates and Quantitative Analyses) contains the collected quantitative analyses of each of the pipeline projects defined in earlier CARICOM reports, as well as avoided cost and rate impact analyses for certain CARICOM countries. It also assembles the template documents developed to guide or to facilitate financing of future RET projects in the region. As part of Volume II, we present a model and instructions for information memoranda that can assist in compilation of similar documents in connection with future developments.

Volume III (Resource Data or Binder Library) contains the resource data used in the analyses, as well as collected industry information (both quantitative and qualitative) that may prove helpful in developing future RET projects in the CARICOM region. This material is collected in 27 three-ring binders, as well as on a compact disk. Among the material in this volume are documentation of actual transactions in the region, contact lists of suppliers, financiers and other resources, information on the tax and regulatory environment in many of the CARICOM nations, resource assessment material for wind,

geothermal, solar, bagasse, and hydro projects, and manufacturers' information relevant to the various renewable energy technologies.

Each volume contains a table of contents identifying the reports, discussions, documents or materials contained therein and the location of the documents within the volume. It is our hope that the Final Report will be useful as a resource library, in addition to being a realistic evaluation of and guide for commercial financing of RET projects for CARICOM region developers.

Chapter I – Overview of Technical Assistance Tools

Background

Caribbean Renewable Energy Development Programme

The Caribbean Renewable Energy Development Programme (CREDP) is an initiative of the Caribbean Community (CARICOM) Secretariat that aims to remove various barriers to wider use of renewable energy technologies in the region. The Programme offers an umbrella under which the participating CREDP countries can receive support in facilitating the development of projects that produce energy from renewable resources. The CREDP is financed by the Global Energy Facility (GEF) and implemented by the United Nations Development Programme (UNDP). It is also assisted by the German Technical Assistance Agency (GTZ).

Concerted national efforts to implement energy initiatives consistent with environmental sustainability (renewable energy projects, in particular) are constrained in two major groups of countries: (1) developed nations with the financial resources but not the motivation to change policies; and (2) developing nations that may have the commitment but lack ample means. One common element in both situations is the presence of economic incentives to pursue renewable energy technology initiatives that are often ignored. Renewable projects are rationally pursued in many natural and economic circumstances -- not simply because they are good for the world's environment, but because they offer identifiable economic opportunities.[2]

While the environmental benefits (*e.g.*, less carbon dioxide emissions) and societal gains (*e.g.*, reduced reliance on imported fuel) are a key aspect of developing renewable resources in the Caribbean, the principal focus of our analytical efforts is the economic aspect of renewable energy technologies (RET). Economically viable and commercially financed RET projects can help utilities and regulators assure the provision of safe, reliable, and reasonably priced energy. At the same time renewable energy projects can advance public policies that encourage energy independence and environmental improvement.

The project seeks to address barriers in four specific areas: Policy, Finance, Capacity Building, and Awareness/Information. CREDP has addressed some of these areas in earlier phases of the project. For example, Phase 1 of CREDP, established in 1998 to promote the use of renewable energy in the region, addressed information and awareness for potential renewable resources in the region. This consultancy is a component of

---

[2] Governmental or multi-lateral organization incentives are often important elements of the economic opportunities that RET projects may offer. In this respect, however, RET projects are not very different from more established energy technologies, which continue to receive assistance from governmental sources.

CREDP that directly addresses technical assistance to renewable resource developments including the financing of projects.

The focus of the consultancy effort that culminates in this report and associated deliverables is to provide technical assistance tools so that renewable energy technology projects in the Caribbean can achieve financing and complete development. From its inception, the approach to this project has been distinctive. In its RFP, the CARICOM Secretariat took a decidedly practical approach. Instead of extending the investigations and studies it had begun in earlier phases of the CREDP project, CARICOM asked RFP respondents to propose ways to help turn the conceptual projects identified in earlier work into reality, focusing on overcoming the difficulties of gaining commercial financing.

Practical Tools to Promote Development of Renewable Projects

ADICA, in its proposal, embraced that challenge and joined the CARICOM Secretariat in its choice of meaningful, practical assistance over deeper study of theoretical renewable energy possibilities. From the start, a major objective was to avoid producing yet another booklet that would remain unread, collecting dust, on the shelves of stakeholders. Rather, we sought to deliver usable information, analysis, and tools to Caribbean RET developers, financiers, and advocates.

Consistent with that objective, we have developed the following tools: (1) a database of financial contacts; (2) survey information from private financial institutions regarding their willingness to lend to renewable projects; (3) a database of documents required in financing proposals; (4) a database of cost and financial data from utility companies to evaluate the effect of renewable resource projects on rates; (5) survey results from utility companies on purchased power agreements; (6) databases of hourly loads and plant characteristics to measure avoided cost; (7) hour by hour avoided cost software; (8) wind resource assessment software tailored to the region; (9) project finance modeling software that applies a database of projects in the region; (10) rate impact and corporate finance modeling software; and (11) a library of reference materials. In addition, template documents and information memoranda are developed to provide guidance for future developers of RET projects as they navigate the waters of the commercial financing process.

These items will remain available to CARICOM -- as guides to future developments and analyses, and as reusable analytical or data-gathering tools, and as new technical assistance capabilities for CARICOM and its clients. This report also presents substantive discussions and guidance respecting commercial financing processes and strategies. Together these items build a regional capacity to prepare renewable energy project documents, feasibility studies, and economic projections in a manner that will support private sector financing, to augment available incentives from multilateral and government financial institutions in the region.

Some specific items produced in this consultancy effort are summarized in the table below. The remarks shown are mainly for descriptive purposes and are not intended to be exhaustive. Each of these items is discussed in greater detail in later sections of the Report or in the presentation of results in other formats.

Table 1 – Technical Assistance to Developers

DELIVERABLES	TECHNICAL ASSISTANCE TO DEVELOPERS
Surveys of Regional Financial Institutions and Utilities	- Responses to ADICA-developed questionnaires and interviews from regional institutions possessing non-public information about financing practices and utility requirements that are central to successful RET projects in the Caribbean. - The survey instruments developed remain available to CARICOM for further research or updates. - Though the depth and quality of the response varies widely, there are valuable indicia of regional practices, preferences and limiting factors.
Quantitative Analyses of CARICOM Pipeline Projects	- Hard quantitative analyses, using regional resource and cost data, of pipeline projects. - These representative results are valuable as guides for developers and utilities considering RET generation or substitutes. - Informed estimates of the range of the "costs to beat" in regional utility territories and countries.
Template Documents for Commercial Financing	- Pattern documents that should enable developers to present their proposals most effectively to potential financial supporters.
Analytical Software Tools and Training	- Software modeling tools that incorporate representative regional data and other distinctive aspects of Caribbean RET developments.
Project Report	- Substantive discussion of RET issues and problems, with suggested strategies. - Templates or exemplars for critical documents. - Library of research materials.

CARICOM's Future Role in Promoting Renewable Projects

In previous studies, CARICOM has taken a unique approach to assisting regional RET efforts. In Phase I of CREDP, the basic objective was to strengthen the regional network of institutions -- resources such as CEIS and UWI-CERMES. Those institutions were relied upon to raise awareness about renewable energy technologies and to serve as the repositories and dispensers of newly acquired or developed knowledge about renewables. With the information and products delivered in this report, the CARICOM Secretariat is poised to expand its technical assistance role. Rather than merely providing support to institutions and entities that support renewable energy technologies, CARICOM can now provide direct assistance to developers, financial institutions, and utilities.

The Secretariat will have information, analytical tools, and training that should put it at the center of RET development efforts in the region. With the completion of activities described in this report, the CARICOM Secretariat will possess a database of previously unassembled information, templates to facilitate (and enhance) developers' commercial lending efforts, and analytical tools that are not readily available in the region -- even to many utilities. With these capabilities, the vigor with which CARICOM pursues

commercial RET financing and development (and the manner in which it does so) will be determined by the relevant markets and its own policies, not by limited functional abilities.

With the assistance of the CARICOM Secretariat and the technical assistance tools documented in this report, local developers or agencies will have the capacity to prepare renewable energy project documents, feasibility studies and economic projections in line with methods used by targeted funding sources, commercial lenders in particular. Utilities will be able to assess, on realistic and informed bases, the benefits of including RET resources in their generation portfolios and appropriate pricing in revenue contracts. And, local financial institutions can confidently evaluate the risks and opportunities of RET project financing, even as they start up the learning curve.

Project Scope and Approach

This consultancy began with a kick-off meeting of the ADICA principals and CARICOM professionals involved with the Secretariat's RET initiatives at CARICOM's Georgetown, Guyana headquarters. There, the core objectives and approaches that were proposed in ADICA's response to the CARICOM RFP were confirmed as appropriate for use in this effort. The particulars of the tasks ADICA would undertake in this consultancy were defined in a detailed Work Plan that was based on those fundamental elements of our proposal to CARICOM affirmed in Georgetown. Those fundamental elements were refined as to specifics through discussions with CARICOM. Cooperatively, we worked with CARICOM to prioritize specific included tasks and to define the scope and depth of the project analyses. The result was the detailed work plan. (That process of adjustment and refinement through communication between ADICA and CARICOM has continued throughout this consultancy, and it accounts in large part for the accomplishments of this consultancy.)

The agreed work plan incorporated the following work plan.

Table 2 - Project Deliverables

ADICA CREDP PROJECT PLAN	
DELIVERABLES	**COMMENTS**
»Detailed Work Plan	»Developed at Kick-Off Meeting and in later discussions »CARICOM provision of remaining information and contacts
»Questionnaires (with Term Sheet) and Survey Plan »Feasibility Studies Work Plan (Pre-Feasibility and Feasibility Study Formats) »*Draft* Transaction Document Templates	»Questionnaires and term sheet for surveys »Pre-Feasibility and Feasibility Studies work plan, with outline of study reports
»*Draft* Pre-Feasibility and Feasibility Studies »Survey Results »Final Template Documents	»Preliminary study results and recommendations »Raw survey results received to date »Final revisions to use survey results

»*Draft* Final Report »Final Pre-Feasibility and Feasibility Studies	»Draft of report with list of attachments »Individual project analysis results
»Final Project Report »Project Information Memoranda »Software Tools and Data	»Finalized with CREDP input »Project financing packages

* Completion of certain tasks in this plan depends upon timely provision of quantitative data or other responses by regional third parties.

Survey Plan and Questionnaires

The planning process for the surveys of potential regional RET project stakeholders began with development of the substantive questions to be used to acquire the information needed for effective financing efforts for pipeline projects. Specifically, we surveyed two groups critical to RET developments -- regional utilities and financial institutions active in the Caribbean. Because RET developers had been identified through earlier CARICOM projects, we were able to consult them through individual interviews.

With respect to the surveys, we were aided by the advice of several regional professional with experience and contacts in the region, including the CREDP Director, Dr. Roland Clarke and Enid Bissember of CARICOM. With their guidance, we were able to identify the correct financial institutions and utilities to survey, the best strategies for garnering the greatest practicable number of responses, and the credible sources for useful insightful guidance. The list of financial institutions is important in itself as it provides a databank of financial contacts for prospective transactions.

The survey process and the distinctive instruments for questioning the respondents were developed through an interactive process of comment and revision with CARICOM and regional consultants. The survey processes were adjusted to improve the timeliness and content of survey responses. For example, we were advised that telephone contacts with developers would likely be more productive than written survey instruments. Similarly, seeking questionnaire responses through interviews, we were told, would be preferable to less spontaneous and less candid written responses. The utility sector was contacted through the offices of CARILEC.

The objectives of the questionnaires included not only gathering relevant quantitative data from financial institutions, developers and utility companies, but to gain specific qualitative information regarding matters such as required PPA terms, realistic financing mechanisms, loan interest ranges, and regulatory constraints on utility relationships with RET projects. Consequently, supplementing written instruments with follow-up conversations (and face to face meetings) was an important aspect of the survey process.

The surveys are not yet fully completed as we submit this Final Report,[3] but the responses received have been valuable in providing actual regional data and information. The financial survey results demonstrate a generally positive attitude for private local capital for renewable projects. The utility surveys show a diversity of attitudes towards private development, and a generally constructive position with respect to economic analysis of renewable technologies.

A summary of selected responses from the utility surveys received to date are presented in the table below.

	Antigua	Bahamas	Belize	B.V.I.	Curacao	Grenada	Montserrat	Trinidad
Do utility laws prohibit your company from signing a PPA	No	Yes	No	Yes	No	No	Yes	No
Has your company:								
Signed PPAs w/ independent generation companies	Yes	No	Yes	No	Yes	No	No	No
Undertaken RET projects of its own	No	No	No	No	Yes	No	No	No
Computed its avoided cost	No	No	Yes	No	Yes	No		No
Most realistic option for developing RET projects:	The utility law allows independent generation	Utility law does not allow generation from independent generation entities	The utility law allows independent generation	The utility law does not allow generation from independent generation entities, but it's possible to change the law	The utility law allows independent generation	The utility law allows independent generation		n/a
In developing PPAs with IPPs, the PPA would be negotiated between company & developer:	W/out need for approval from regulators/gov't agencies	With the approval by regulatory agencies	With the approval by regulatory agencies	Reg/gov't agencies directly involved in negotiating PPAs.	W/out need for approval from regulators/gov't agencies	With the approval by regulatory agencies		n/a
Process for determining price terms for a PPA:	We do not know at this time	We do not know at this time	Negotiate prices from a variety of factors	We do not know at this time	Negotiate prices from a variety of factors	We do not know at this time	We do not know at this time	Negotiate prices from a variety of factors
With respect to calculation of avoided cost, we compute:	We have not computed avoided cost	We have not computed avoided cost	Cost of fuel, variable O&M costs, cost of building new plant, line losses on the T&D system	We have not computed avoided cost	Cost of fuel, variable O&M costs, cost of building new plant	Cost of fuel, variable O&M costs, line losses on the T&D system		We have not computed avoided cost
What types of analysis would your company require to invest in an RET project?	Technical, System disturbance, economic viability	Comparison of rates of return, would have to be a postive NPV project.	Company included as an output in a least cost generation planning run	Reliant on what the government in council wishes to pursue	LOLP, avoided cost, dynamic grid study for voltage stability, system control	Avoided, installed, & running costs, environmental impact analysis	Avoided fuel, maintenance cost	NPV, IRR, Payback. Expected EA and EFOF
What types of analysis would your company require to sign a PPA?	Track record, technical/financial ability	Financial viability, economic burden, regulatory issues, sustainability of agreement	Least cost generation planning run & competitive bidding	Reliant on what the government in council wishes to pursue	Financial analysis, dynamic grid study for voltage stability, system control	Financial stability, track record of successful projects, proposed business model		NPV, IRR, Payback. Expected EA and EFOF
What principal concerns would your company have in signing a PPA w/a "non-utility" generator?	Grid stability, financial stability	Financial viability, economic burden, grid stability, reliability	Viability, grid stability, etc. Would have to be addressed in PPA	Reliability of source, aesthetic value	Financial analysis, dynamic grid study for voltage stability, system control, continuity of operation	Avoided costs, financial stability, track records, etc.		n/a -- T&TEC

Figure 1 - Summary of Utility Survey Responses

We prepared two surveys for distribution to financial institutions. One survey was aimed at banks and other financial institutions that have not yet completed project financing transactions, while another was developed for banks that have completed such transactions. The former survey was primarily a discrete choice questionaire and covered general issues, while the latter used open-ended questions and delved in detail into financing issues.

Results of the financial surveys have provided valuable insights on: the willingness of regional institutions to fund renewable projects (institutions expressed a general willingness); the process and documents required in applying for loans; the amount of

[3] As noted at other places in this report, the questionnaires have been distributed and all future response will be returned to CARICOM. The survey protocols and survey instruments remain in the possession of CARICOM, so that the results may be updated at any time by re-canvassing stakeholders.

funding that can be obtained for individual projects; the length of debt and the interest rates on loans; and the underwriting process used to assess risk.

Even without the survey responses, the survey process itself has been valuable to CARICOM for the future. First, administration of the surveys required compilation of a database of financial contacts. This database will enable developers to send funding proposals to a number of financial institutions without having to do the research. Second, the surveys themselves provide a guide for considering the type of issues that must be addressed in submitting proposals to banks. In other words, developers can examine each question in the survey and work through what they should submit, request, or expect in a loan proposal.

The survey instruments and the distribution list for implementing the surveys are provided to CARICOM in this Final Report in Annex I and Annex II.

Template Documents

ADICA has identified those financial transaction documents that are essential components of nearly all developments that use project financing arrangements as the vehicle for commercial loan support. Templates (exemplars of the document types) to facilitate commercial lending arrangements for current and future developers were developed for those documents. Central to RET project financings is the power purchase agreement. While project financing is theoretically possible without one, it is fundamental for RET projects in new or developing markets and no history of revenue production. Templates were also produced for the interconnection arrangements with off-taker utilities, and O&M specifications to assure the utility of reliable production. Those templates, as well as samples of other more distinctive documents that have been used in particular energy project financings, are provided with this Final Report.

The questionnaires were designed to elicit information and data that could inform our identification of critical transaction documents and our development of templates. The templates can facilitate action by developers, bankers, utilities, policy decision makers, and government officials in advancing the financing of renewable energy production facilities.

Construction of template documents began with our collection of an extensive sample of transaction documents, including examples from in the Caribbean and other developing areas. We reviewed a variety of financing transaction documents, for both renewable and non-renewable technologies, The documents analyzed included PPAs, financing term sheets, offering memoranda, operation and maintenance specifications, project finance spreadsheet models, and other items associated with energy project financings.

The list of documents and resources shown below relates principally to non-recourse financing arrangements. Other documents relate to providing technical assistance for vendor and customer finance related to off-grid projects such as solar water heaters. This

slate of documents was evaluated in light of input from various sources we consulted (both inside and outside the region).

Table 3 - Transaction Documents

DOCUMENT	COMMENTS
Purchased Power Agreement	·This most important document in gaining financing may contain prices based on avoided costs or fixed capacity and energy prices.
Construction Loan (3)	·The construction loan funds building of the project. It specifies draw down provisions, required equity contributions, credit spread, etc. ·In project financing arrangements, a permanent loan may replace the construction loan once the facility is operational.
Term Sheet	·A concise summary of the economic terms of a proposed project financing. ·Term Sheets are sometimes the basis for decisions or negotiations on a financing, though a full package of documents may be appropriate for the most effective presentation to potential financing sources.
Permanent Loan	·In project financing, this debt is incurred on the basis of revenues from the operational project. · Sometimes replaces a related construction loan. In addition to loan covenants and repayment terms, the document defines the priority of claims on project cash flow.
Interconnection Agreement	·Interconnection with the grid to which energy production from the project will is a precondition to delivery of and revenues from energy output. ·In most cases, given the size and complexity of Caribbean grids, the necessary provisions can be incorporated into the PPA.
Equipment, Procurement & Construction (EPC) Contract	· For RET equipment, manufacturers may offer the best deals, using their own standard agreements. ·Such manufacturer's deals may be fixed price, turnkey contracts with favorable financing terms.
O&M Contract/Specifications	·Local maintenance of RET projects is a worthwhile goal, but manufacturer support is more practical, and would typically be dome under a standard contract.
Information Memorandum	·The information memorandum is not a contract, but it is a main marketing tool for potential sources of financing. It describes the project, the market and economic projections that form the basis for project finance. A sample information memorandum was prepared and is included.

Quantitative Project Analyses

The heart of this consultancy was the development of sophisticated quantitative models with which we analyzed analyses pertinent to Caribbean RET developments. We began, as requested in the project RFP, with an assessment of each of the projects in the CARICOM pipeline. These analyses provide perspective needed for economic viability consideration and for effective presentations to financial institutions. Some pipeline projects already had partially completed feasibility analyses; others already had financing.

Our analysis evaluates the CARICOM pipeline projects and the regional economic environments from three distinct perspectives – developer, utility, and financier. The analytical software tools include an hour-by-hour system simulation model, an integrated project finance model, and a utility financial model. These three models are the tools that enabled the comprehensive analyses. Avoided cost analysis provides the developer with information needed to determine whether the relevant market for electricity will support the proposed project.

The rate impact model tells utilities how the inclusion of RET projects in the production portfolio will affect their costs and their customers' rates. A realistic view of the effects of the project puts all parties on a common ground of information, and may make the negotiations necessary for project completion less susceptible to failure due to unrealistic expectations.

The quantitative analyses were performed using proprietary software tools that evaluate the financial viability of each project, assessed against developed avoided costs of the pertinent CARICOM member country and using the CREDP specification of avoided costs. For the projects in the pipeline, ADICA subjected the projects to analysis using combinations of system simulation models, project finance models and financial/rate projection models as necessary to complete the prescribed suite of analyses. This analysis provides technical support to development and finance of projects.

The bulk of this report describes analyses we have completed using survey responses, models of projects, and models of utility systems in the Caribbean. Some of the analytical results include:

Findings & Recommendations

➢ Renewable Resources are Economically Viable

Many types of renewable resources are economically viable in the Caribbean region without subsidy support from national governments or from local utility companies:

- Most countries in the region possess a variety of renewable resources – hydro, volcanic origin islands with geothermal potential, islands with significant winds, strong sunlight for extended portions of the year. The wind resources in many Caribbean countries (wind speed and profiles) hold the promise of wind power production with better capacity factors

than almost anywhere else in the world. The graph below of capacity factors illustrates the wind resource potential of Caribbean projects, which compares favourably to other wind farms.

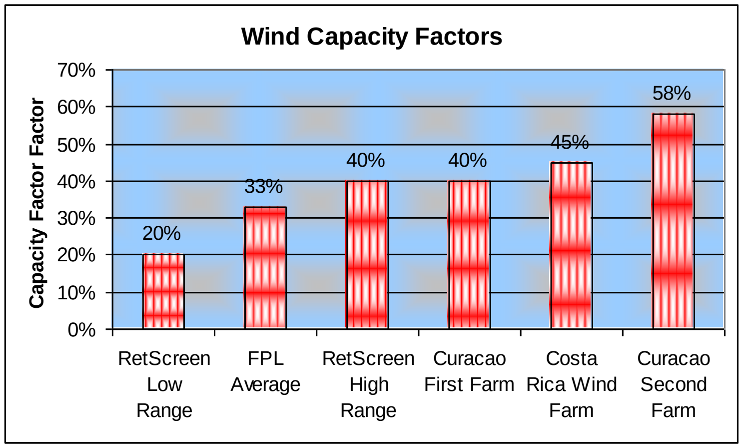


Figure 2 - Wind Capacity Factors

- The economic viability of projects is driven by the fact that costs which are avoided by utility companies from renewable energy are greater than the cost of operating and financing renewable projects. Simple evidence of the high avoided cost in the region is the high level or retail rates charged by most of the utility companies. The chart below compares retail rates in various CARICOM countries with rates in the US:

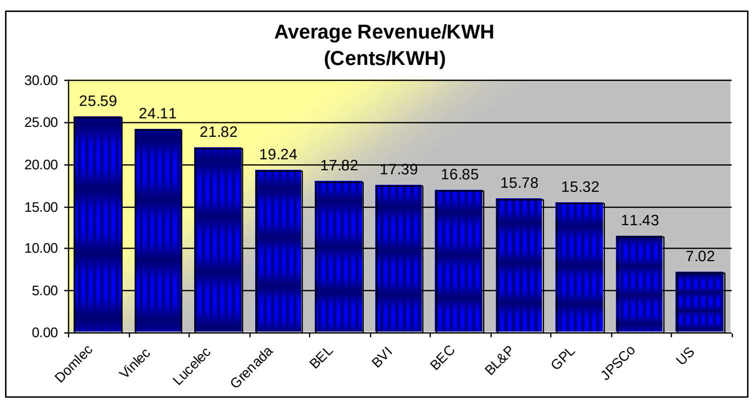


Figure 3 – Average Revenue/KWH

- Due to the relatively small size of electric systems in the region, the renewable resources can represent a large component of total electricity energy produced. For some systems such as Dominica, Grenada, St. Lucia, and St. Vincent, the small size of the electricity systems and the availability of geothermal and wind resources means that renewable

technologies can represent the majority of resources for a country. The table below shows the amount of renewable energy from the CARICOM pipeline projects relative to total energy production in various countries:

	Pipeline Data (1)			Renewable as a Percent of Energy Generation	
	Capacity kW	Cap Factor Percent	Generation GWH	CARICOM Pipeline	CARICOM plus Existing
Antigua	2,000.0	27.0%	4.7	1.8%	1.8%
Bahamas				0.0%	0.0%
Barbados Wind	6,000.0	34.5%	18.1		
Barbados Off Shore Wind	50,600.0	40.0%	177.3		
Barbados Landfill Gas	1,433.0	69.0%	8.7		
Total Barbados	58,033.0		204.1	24.6%	24.6%
Belize Biogasse	12,000.0	75.0%	78.8		
Belize Hydro	2,800.0	44.8%	11.0		
Total Belize	14,800.0		89.8	30.6%	84.8%
British Virgin Islands				0.0%	0.0%
Dominica Wind	3,000.0	42.8%	11.2		
Dominica Hydro	228.0	45.0%	0.9		
Dominica Geothermal	12,000.0	92.0%	96.7		
Total Dominica	15,228.0		108.9	134.5%	167.9%
Grenada Wind	1,200.0	36.6%	3.8		
Grenada Geothermal	12,000.0	90.0%	94.6		
Total Grenada	13,200.0		98.5	68.9%	68.9%
Guyana Wind	9,500.0	33.8%	28.1		
Guyana Hydro	100,000.0	88.0%	770.9		
Total Guyana	109,500.0		799.0	158.2%	158.2%
Jamica Cogen	70,000.0	71.8%	440.3		
Wigton	20,700.0	33.8%	61.3		
Jamica Hydro	2,000.0	40.0%	7.0		
Total Jamica	92,700.0		508.6	14.9%	16.9%
Montserrat Geothermal	4,000.0	90.0%	31.5		
Montserrat Geothermal	5,000.0	90.0%	39.4		
Total Montserrat	9,000.0		71.0	NA	
Nevis Wind	3,250.0	27.1%	7.7		
Nevs Geothermal	4,000.0	93.0%	32.6		
Total Nevis	7,250.0		40.3	NA	
St. Lucia Wind	15,000.0	30.9%	40.6		
St Lucia Geothermal	10,000.0	90.0%	78.8		
Total St Lucia	25,000.0		119.4	41.7%	41.7%
St. Vincent Wind	700.0	36.0%	2.2		
St Vincent Geothermal	12,000.0	93.0%	97.8		
Total St Vincent	12,700.0		100.0	101.2%	119.9%

Figure 4

- The economic viability of renewable projects in the region is illustrated by the proposed geothermal project in Grenada. The chart below shows how, relative to a "status quo" case with no renewable resources, the geothermal plant saves more than $45 million in costs after payment of financing and operating costs for the plant. The single geothermal facility results in annual savings of more than 20% for the entire system. Similar economically viability analyses are developed for different modelling techniques and for alternative projects in the pipeline:

Status Quo Case	1	Monte Carlo Status Quo - No Emissions								
Renewable Case	2	Geothermal - Monte Carlo/No Emissions								
PPA Price ($/MWH)	62									
Economic Analysis of Renewable Projects	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Varible Costs (Fuel and Variable O&M)										
Status Quo Case	11,126,536	15,206,351	13,737,279	14,340,317	15,756,457	18,225,262	19,225,798	20,669,346	23,091,667	24,562,491
Renewable Resource Case	11,126,536	15,206,351	5,389,019	6,582,226	7,774,945	9,751,857	10,752,263	12,010,687	14,837,905	16,117,316
Variable Cost Savings	-	-	8,348,260	7,758,090	7,981,511	8,473,405	8,473,535	8,658,660	8,253,762	8,445,175
Capacity Costs										
Status Quo Case	-	-	1,173,149	1,793,640	2,436,724	2,482,003	3,187,174	3,892,378	4,125,273	5,077,252
Renewable Resource Case	-	-	82	30	609,181	620,524	1,274,831	1,946,092	1,650,129	2,538,541
Capacity Cost Savings	-	-	1,173,067	1,793,610	1,827,543	1,861,479	1,912,342	1,946,286	2,475,144	2,538,711
Cost of Un-Served Energy										
Status Quo Case	49,767	125,838	94,265	69,751	11,393	27,438	42,269	22,746	66,122	8,503
Renewable Resource Case	49,767	125,838	83,093	126,717	79,140	153,403	115,945	159,813	110,849	111,824
Reliability Savings	-	-	11,173	(56,966)	(67,747)	(125,965)	(73,675)	(137,068)	(44,727)	(103,322)
Total Savings from Renewable Resouces	-	-	9,532,500	9,494,734	9,741,307	10,208,919	10,312,202	10,467,878	10,684,179	10,880,564
Gross Savings Percent	0%	0%	69%	66%	62%	56%	54%	51%	46%	44%
PPA Price/MWH	62.00	62.00	62.00	62.00	63.24	64.50	65.79	67.11	68.45	69.82
Renewable Energy (GWH)	-	-	97,228	97,384	97,086	97,611	97,272	97,451	97,319	96,899
Total Cost of Renewable Resource	-	-	6,028,123	6,037,809	6,139,745	6,296,398	6,399,978	6,540,029	6,661,794	6,765,722
Net Savings	-	-	3,504,377	3,456,925	3,601,563	3,912,521	3,912,224	3,927,850	4,022,384	4,114,842
Net Savings Percent	0%	0%	26%	24%	23%	21%	20%	19%	17%	17%
Discount Rate	7.0%									
Present Value of Savings over 25 years	$45,051,303		PV of Varible Cost Savings		$93,273,875					
			PV of Capacity Cost Savings		$19,607,478					
kW	12,000.00		PV of Reliabiility Savings		($460,836)					
$/kW	2,083.00		Total Savings		$112,420,517					
Total Cost	$ 24,996,000.00									
			PV of PPA Costs		$67,369,214					
			Net Savings		$45,051,303					

Figure 5 – Savings from Grenada Geothermal Facility

➢ High Avoided Costs are a Key Driver of Economic Viability

One of the primary reasons that renewable resources are economically viable in the region is the high cost of fuel, variable operation and maintenance expenses, capital expenditures and energy losses that are avoided when renewable projects are developed:

- The principal driver for the high avoided costs is the cost of imported fuel. These costs are so significant that renewable projects are economically viable without including more difficult to measure avoided variable operation and maintenance costs, avoided CO2 emissions, avoided capacity costs, and avoided line losses. The chart below illustrates the high cost of fuel in the region (by comparison, the cost of fuel for a US utility company is typically between $15/MWH and $25/MWH.)

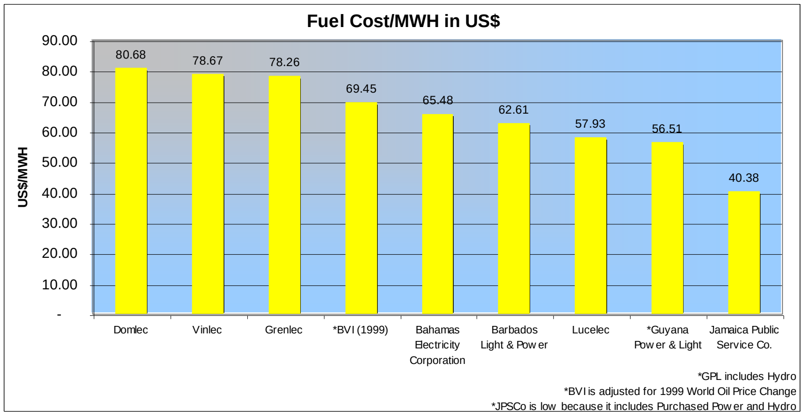


Figure 6 – Fuel Cost/MWH

- Avoiding payment of fuel costs is important to the region from a public policy standpoint because through developing renewable projects, CARICOM countries can recapture significant revenues now paid to foreign fossil fuel providers.

- Detailed avoided cost analysis using hourly dispatch modelling showed that actual avoided costs in the region (developed using hourly loads and system dispatch) are significantly higher than the average fuel cost. As compared to the $78/MWH fuel cost for Grenada, avoided cost ranges between $90/MWH and $100/MWH as shown on the graph below:

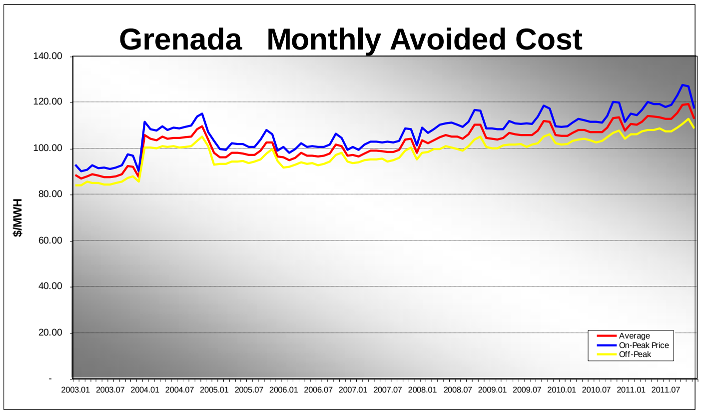


Figure 7 – Grenada Monthly Avoided Cost

- When renewable resources are developed, some expenses incurred to operate and maintain plants will be reduced – variable operation and maintenance expenses. Variable O&M expenses are high in the region due to the maintenance intensive nature of diesel capacity used in the region, as shown in the graph below:

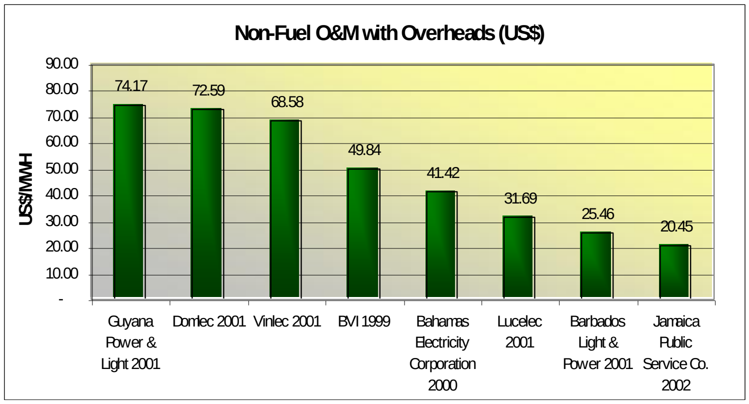


Figure 8 – Non-Fuel O&M

- Renewable resources reduce the amount of new capacity that is required to meet load requirements on a system. Geothermal plants have high avoided capacity costs because of the high reliability of these plants. Wind resources avoid less capacity because they cannot be relied on to produce electricity when it is needed at times of system peak. Avoided capacity costs in CARICOM are driven by the cost of installing new diesel plants. The graph below shows that the cost per kW of diesel capacity ranges between $570/kW to $1,400/kW:

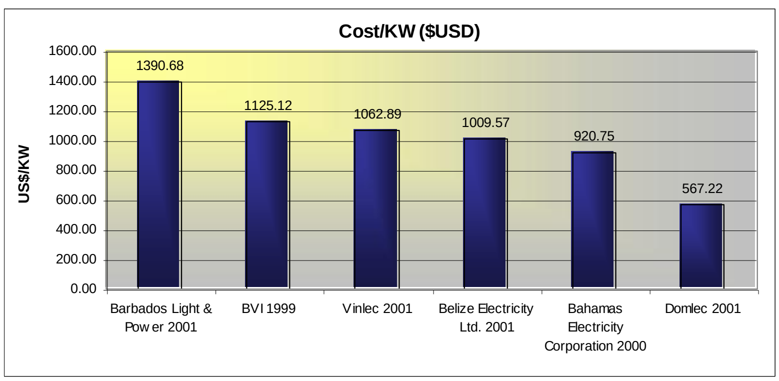


Figure 9 – Cost/KW

- Off-grid renewable projects such as solar water heaters reduce the amount of line losses and distribution costs in addition to the avoided fuel costs, avoided variable operation and maintenance costs, avoided capacity costs and avoided emissions costs. Line losses are high for many of the utility systems in the region as demonstrated on the chart below:

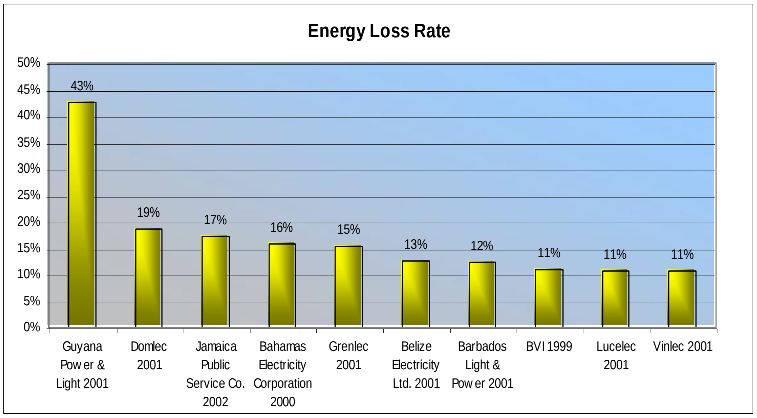


Figure 10 – Energy Loss Rate

➢ Financing of Renewable Projects from Regional Financial Institutions (Chapter 2)

Due to the relatively small size of renewable projects and the complexity of obtaining guarantees and political risk insurance required by large international financial institutions, local funding is an attractive source for many renewable projects:

- A wind farm in Jamaica obtained 83% debt financing and a 7.5% interest rate from a regional bank. This financing which was supported by a guarantee from the Jamaican government, which was crucial in making the project economic.

- Survey results indicate that many regional banks are willing to fund renewable projects with reasonable terms. Issues addressed in the survey include the loan process, debt terms (length and repayment), debt sizing (leverage levels), debt pricing (interest rates) and loan underwriting (risk analysis).

- Risks associated with drilling for geothermal resources imply that high levels of debt financing cannot be obtained until the resources are established. On the other hand, wind projects with relatively short construction periods and little uncertainty with respect to construction costs should be able to obtain more favourable financing terms.

- The financing process for a private developer involves developing an information memorandum; negotiating a purchased power agreement with a utility company; possibly establishing contracts to construct the facility (EPC contracts); proposing financing terms and terms of a loan agreement; completing an operation and maintenance agreement; and potentially drafting various contracts. Negotiating these contracts can add a great deal

of cost to small renewable projects. The costs can be alleviated by template documents used on a consistent basis throughout the region.

- Programs to moderate the financing, legal, consulting and other set-up costs through using template documents have been developed in Australia for hydro plants and in the US for natural gas fired merchant plants.

➢ Project Finance Models (Chapter 3)

The cost of financing and operating renewable projects depends on a variety of tax, financing, resource assessment, capital cost, transmission, and other assumptions. The costs (also termed minimum required PPA prices) of most projects in the region are below avoided costs under a variety of different assumptions.

- The most important variables that affect the cost of renewable projects include the amount of development cost, the length of construction, the availability of subsidies, the capacity factor, inflation in the PPA agreement, and financing terms. The table below illustrates how the costs and rates of return of a wind facility in Grenada vary with different assumptions. The mechanics and interpretation of the table are explained in Chapter 3:

Simulate		Case -->	Grenada Wind			Capactiy Factor		39.0%		PPA Inflation	2.00%	
						Plant Life		20		O&M Inflation	0.00%	
						Base Plant Cost/kW		1,111.07		Debt Repay	15.00	
	Avoided Cost	Equity IRR	Project IRR	Average DSCR	Minimum DSCR	Plant Life Coverage (PLCR)	Minimum PPA Price	Price vs Base	O&M/Plant	Target IRR	Debt/Capital	Cost per kW w/ Constr Interest
Base	72.60	15.27%	9.71%	1.83	1.50	2.10	$ 57.83		6.14%	15.00%	62.13%	$ 1,085.0
Base	72.60	18.56%	11.4%	2.07	1.69	2.38	$ 57.30		6.14%	15.0%	62.13%	$ 1,085.0
No Development Cost	72.60	15.48%	9.8%	2.04	1.67	2.35	$ 63.47		6.14%	15.0%	55.20%	$ 1,290.1
No Grant on Wind Generator	72.60	13.46%	8.9%	1.67	1.39	1.92	$ 68.27		6.14%	15.0%	63.83%	$ 1,389.2
Higher Capacity Factor	72.60	26.38%	15.6%	2.72	2.19	3.15	$ 46.13		8.50%	15.0%	62.13%	$ 1,085.0
Lower Capacity Factor	72.60	16.22%	10.2%	1.89	1.56	2.18	$ 61.90		5.51%	15.0%	62.13%	$ 1,085.0
High O&M Cost and Inflation	72.60	18.33%	10.8%	1.97	1.84	2.25	$ 58.53		4.61%	15.0%	62.13%	$ 1,085.0
Low O&M Cost and Inflation	72.60	24.01%	14.2%	2.48	2.11	2.86	$ 45.41		1.84%	15.0%	62.13%	$ 1,085.0
High O&M Inflation	72.60	15.01%	9.1%	1.74	1.54	1.97	$ 64.60		6.14%	15.0%	62.13%	$ 1,085.0
10 Year Tax Holiday	72.60	22.49%	14.2%	2.31	1.98	2.66	$ 53.24		6.14%	15.0%	62.13%	$ 1,085.0
25 Year Tax Holiday	72.60	23.38%	15.1%	2.50	1.98	2.90	$ 51.48		6.14%	15.0%	62.13%	$ 1,085.0
Accelerated Tax Depreciation	72.60	18.56%	11.4%	2.07	1.69	2.38	$ 57.30		6.14%	15.0%	62.13%	$ 1,085.0
5 Year Tax Life	72.60	21.25%	12.3%	2.13	1.86	2.48	$ 54.25		6.14%	15.0%	62.13%	$ 1,085.0
High Transmission Cost	72.60	19.43%	11.9%	2.14	1.75	2.47	$ 55.73		6.36%	15.0%	61.92%	$ 1,041.9
Longer Plant Life	72.60	18.99%	12.5%	2.03	1.66	2.83	$ 55.30		6.14%	15.0%	62.13%	$ 1,085.0
3% PPA Inflation	72.60	19.27%	12.0%	2.16	1.69	2.51	$ 55.62		6.14%	15.0%	62.13%	$ 1,085.0
15% Environmental Adder	72.60	22.91%	13.7%	2.41	1.98	2.79	$ 49.83		6.14%	15.0%	62.13%	$ 1,085.0
12% IRR Target	72.60	18.56%	11.4%	2.07	1.69	2.38	$ 51.55		6.14%	12.0%	62.13%	$ 1,085.0
18% IRR Target	72.60	18.56%	11.4%	2.07	1.69	2.38	$ 63.44		6.14%	18.0%	62.13%	$ 1,085.0
75% Financing	72.60	19.40%	11.3%	1.93	1.59	2.22	$ 56.19		6.14%	15.0%	66.34%	$ 1,096.2
60% Financing	72.60	17.23%	11.6%	2.41	1.96	2.78	$ 59.44		6.14%	15.0%	53.79%	$ 1,063.6
9% Interest Rate	72.60	17.35%	11.3%	1.87	1.58	2.12	$ 59.82		6.14%	15.0%	62.11%	$ 1,093.2
8 Year Bond Life	72.60	15.70%	11.4%	1.31	1.11	2.33	$ 62.84		6.14%	15.0%	61.95%	$ 1,085.4
Level Payments	72.60	17.54%	11.4%	2.18	1.36	2.37	$ 59.03		6.14%	15.0%	62.13%	$ 1,085.0
No Debt Service Reserve	72.60	18.56%	11.9%	1.93	1.62	2.19	$ 57.63		6.14%	15.0%	62.68%	$ 1,092.0
Worst Case Financing	72.60	14.14%	11.3%	1.30	0.97	2.19	$ 67.04		6.14%	15.0%	57.74%	$ 1,082.3
High PPA Price	72.60	9.79%	8.2%	1.31	0.93	1.71	$ 80.18		6.36%	15.0%	59.29%	$ 1,344.3
Low PPA Case	72.60	25.25%	16.6%	2.67	2.04	3.63	$ 47.49		6.14%	15.0%	62.65%	$ 1,084.1

Figure 11 – Grenada Wind

- Using likely case financing, tax, development and other assumptions – including no grants and 65% debt leverage – most of the pipeline projects are economic in the sense that the costs of financing and operating the

plants (the minimum PPA price) is below the estimated avoided cost as shown on the table below:

	Capacity Factor	Capital Cost/kW	O&M per MWH	Avoided Cost $/MWH	Equity IRR	Project IRR	Average DSCR	Minimum DSCR	PLCR	Minimum PPA Price	Price vs Avoided Cost	O&M/Plant	Target IRR	Debt/Capital
Wigton	33.8%	1,219.49	12.00	56.00	5.20%	5.16%	1.74	1.60	2.01	74.92	(18.92)	2.91%	15.00%	65.00%
Antigua Wind	27.0%	1,496.80	12.17	85.80	7.27%	6.05%	1.77	1.56	2.04	108.94	(23.14)	1.92%	15.00%	65.00%
Barbados Wind	34.5%	1,106.73	11.24	70.00	13.03%	8.89%	1.88	1.62	2.16	67.78	2.22	3.07%	15.00%	61.84%
Dominica Wind	42.8%	1,810.77	11.73	105.00	21.00%	13.26%	1.79	1.52	2.06	76.68	28.32	2.43%	15.00%	65.00%
Grenada Wind	36.6%	1,111.07	19.97	105.00	21.91%	13.78%	1.94	1.62	2.24	73.16	31.84	5.76%	15.00%	59.49%
Guyana Wind	33.8%	944.41	12.27	90.00	23.85%	14.63%	1.88	1.60	2.16	58.82	31.18	3.85%	15.00%	62.02%
Nevis Wind	27.1%	1,692.80	14.74	90.00	5.97%	5.26%	1.88	1.63	2.16	124.38	(34.38)	2.07%	15.00%	61.71%
St. Lucia Wind	30.9%	1,031.43	10.98	85.00	18.68%	12.10%	1.88	1.61	2.16	65.88	19.12	2.88%	15.00%	62.22%
St. Vincent Wind	36.0%	1,828.00	12.00	85.00	5.21%	5.45%	1.93	1.67	1.90	103.04	(18.04)	2.07%	15.00%	65.00%
Dominica Geothermal	92.0%	2,500.00	12.00	120.00	30.71%	18.92%	1.93	1.63	2.23	59.78	60.22	3.87%	15.00%	65.00%
Grenada Geothermal	90.0%	2,083.00	20.00	120.00	31.58%	19.27%	1.94	1.59	2.23	60.78	59.22	7.57%	15.00%	65.00%
Montserrat Geothermal	90.0%	1,500.00	15.00	150.00	45.65%	26.91%	1.93	1.61	2.22	47.39	102.61	7.88%	15.00%	65.00%
Montserrat Geothermal	90.0%	1,500.00	15.00	150.00	45.65%	26.91%	1.93	1.61	2.22	47.39	102.61	7.88%	15.00%	65.00%
Nevs Geothermal	93.0%	1,500.00	24.78	97.00	32.12%	19.64%	1.96	1.52	2.25	52.02	44.98	13.46%	15.00%	65.00%
St Vincent Geothermal	93.0%	2,083.00	10.00	100.00	29.66%	18.20%	1.93	1.64	2.22	50.82	49.18	3.91%	15.00%	65.00%
St Lucia Geothermal	90.0%	2,000.00	15.00	90.00	24.57%	15.42%	1.93	1.62	2.22	55.76	34.24	5.91%	15.00%	65.00%
Belize Hydro	44.8%	1,250.00	10.00	70.00	17.52%	12.99%	1.80	1.49	2.74	54.80	15.20	3.14%	15.00%	65.00%
Guyana Hydro	88.0%	2,120.00	10.00	80.00	21.05%	14.32%	1.79	1.53	2.67	52.74	27.26	3.64%	15.00%	65.00%
Dominica Hydro	45.0%	3,704.21	24.78	97.00	0.00%	1.89%	1.94	1.65	2.23	188.68	(91.68)	2.64%	15.00%	65.00%
Barbados Off Shore Wind	40.0%	2,000.00	20.00	70.00	0.00%	2.17%	1.92	1.65	2.21	133.81	(63.81)	3.50%	15.00%	65.00%
Barbados Landfill Gas	69.0%	1,758.00	25.00	70.00	7.40%	4.60%	1.69	-	1.85	78.85	(8.85)	8.60%	15.00%	65.00%
Jamica Cogen	71.8%	1,285.71	25.00	65.00	15.91%	11.29%	1.86	1.47	2.41	55.93	9.07	12.23%	15.00%	65.00%
Belize Biogasse	75.0%	1,491.00	25.00	70.00	17.32%	11.64%	2.08	1.64	2.10	58.50	11.50	11.02%	15.00%	65.00%

Figure 12

- Using best case financing, tax, development and other assumptions – including e.g., the grants offered by RET equipment manufacturers' governments, and higher debt leverage – virtually all of the pipeline projects are economic using the project finance model analysis:

Parameter Case Used	Base													
	Capacity Factor	Capital Cost/kW	O&M per MWH	Avoided Cost: $/MWH	Equity IRR	Project IRR	Average DSCR	Minimum DSCR	PLCR	Minimum PPA Price	Price vs Avoided Cost	O&M/Plant	Target IRR	Debt/Capital
Wigton	33.8%	1,219.49	12.00	56.00	14.45%	10.16%	1.36	1.22	1.56	49.03	6.97	2.91%	13.00%	75.00%
Antigua Wind	27.0%	1,496.80	12.17	85.80	20.67%	12.43%	1.39	1.21	1.58	64.45	21.35	1.92%	13.00%	75.00%
Barbados Wind	34.5%	1,106.73	11.24	70.00	29.56%	16.42%	1.47	1.27	1.68	42.77	27.23	3.07%	13.00%	70.38%
Dominica Wind	42.8%	1,810.77	11.73	105.00	45.91%	21.17%	1.40	1.17	1.60	51.54	53.46	2.43%	13.00%	75.00%
Grenada Wind	36.6%	1,111.07	19.97	105.00	42.60%	23.17%	1.51	1.23	1.72	49.85	55.15	5.76%	13.00%	68.45%
Guyana Wind	33.8%	944.41	12.27	90.00	50.21%	25.94%	1.48	1.25	1.69	37.96	52.04	3.85%	13.00%	70.35%
Nevis Wind	27.1%	1,692.80	14.74	90.00	14.30%	10.10%	1.47	1.29	1.68	77.27	12.73	2.07%	13.00%	70.29%
St. Lucia Wind	30.9%	1,031.43	10.98	85.00	39.51%	20.86%	1.48	1.26	1.68	42.41	42.59	2.88%	13.00%	70.58%
St. Vincent Wind	36.0%	1,828.00	12.00	85.00	24.62%	13.15%	1.53	1.30	1.50	61.60	23.40	2.07%	13.00%	75.00%
Dominica Geothermal	92.0%	2,500.00	12.00	120.00	59.11%	30.05%	1.47	1.21	1.68	36.94	83.06	3.87%	13.00%	75.00%
Grenada Geothermal	90.0%	2,083.00	20.00	120.00	62.51%	31.77%	1.47	1.16	1.68	40.03	79.97	7.57%	13.00%	75.00%
Montserrat Geothermal	90.0%	1,500.00	15.00	150.00	90.90%	47.39%	1.46	1.18	1.67	29.83	120.17	7.88%	13.00%	75.00%
Montserrat Geothermal	90.0%	1,500.00	15.00	150.00	90.90%	47.39%	1.46	1.18	1.67	29.83	120.17	7.88%	13.00%	75.00%
Nevs Geothermal	93.0%	1,500.00	24.78	97.00	63.40%	32.32%	1.48	1.06	1.70	37.31	59.69	13.46%	13.00%	75.00%
St Vincent Geothermal	93.0%	2,083.00	10.00	100.00	59.53%	30.19%	1.46	1.22	1.67	30.76	69.24	3.91%	13.00%	75.00%
St Lucia Geothermal	90.0%	2,000.00	15.00	90.00	52.19%	26.55%	1.46	1.19	1.67	34.99	55.01	5.91%	13.00%	75.00%
Belize Hydro	44.8%	1,250.00	10.00	70.00	34.67%	19.35%	1.32	1.06	1.99	32.95	37.05	3.14%	13.00%	75.00%
Guyana Hydro	88.0%	2,120.00	10.00	80.00	46.39%	23.96%	1.33	1.12	1.93	30.43	49.57	3.64%	13.00%	75.00%
Dominica Hydro	45.0%	3,704.21	24.78	97.00	5.63%	6.85%	1.47	1.24	1.67	109.03	(12.03)	2.64%	13.00%	75.00%
Barbados Off Shore Wind	40.0%	2,000.00	20.00	70.00	6.04%	6.96%	1.45	1.25	1.65	75.82	(5.82)	3.50%	13.00%	75.00%
Barbados Landfill Gas	69.0%	1,758.00	25.00	70.00	25.37%	13.09%	1.30	-	1.43	51.37	18.63	8.60%	13.00%	75.00%
Jamica Cogen	71.8%	1,285.71	25.00	65.00	36.18%	19.59%	1.40	1.03	1.79	38.41	26.59	12.23%	13.00%	75.00%
Belize Biogasse	75.0%	1,491.00	25.00	70.00	36.57%	19.30%	1.61	1.17	1.61	42.25	27.75	11.02%	13.00%	75.00%

Figure 13

- Grants provided by certain European countries for renewable projects – by The Netherlands and Denmark to certain countries in the region with relatively low GDP per capita – have a significant effect on the economic viability of renewable projects and should be used whenever feasible.

➢ Resource Assessment (Chapter 4)

The methodology for assessing resources is different for the various types of renewable projects that could be developed in the region. Resource assessment for wind projects involves measuring the hourly distribution (average levels and

deviations from the average) of wind speeds at specific sites; the assessment of geothermal resources is largely resolved once successful drilling has occurred, but subject to large uncertainty during the drilling process; resource assessments for hydro plants involve considering the variation in water flows from year to year; energy production from biomass involves analysis of materials such as sugar cane and the amount produced in different growing seasons; and, resource assessment for solar projects involves evaluation the probability distribution of sunlight:

- Geothermal resource assessments made in many of the islands show strong potential in terms of the heat of steam and the amount of the resource. Once successful drilling has taken place, capacity factors for geothermal plants should be above 90%.

- Hydro facilities have been constructed in the region and they have realized varying capacity factors ranging from 30% to 80%. The hydro resources are run-of-river plants which cannot store water in reservoirs for use at peak times. Hydro resource assessment, environmental impact, and cost estimation is highly site specific.

- Biomass resources consist primarily of bagasse plants which depend on materials from the farming of sugar cane. Problems with resource assessment of bagasse plants have involved the issue of whether there is enough material in non-growing seasons.

- Wind resource assessment should be completed by detailed wind studies and wind mapping for selected sites. Analysis of general wind speeds in the region and site specific adjustments confirms the attractive potential of wind projects. The graph below illustrates the effect of site specific factors on wind speeds in St. Kitts, where average annual wind speeds vary from 3 meters/second to 8 meters/second:

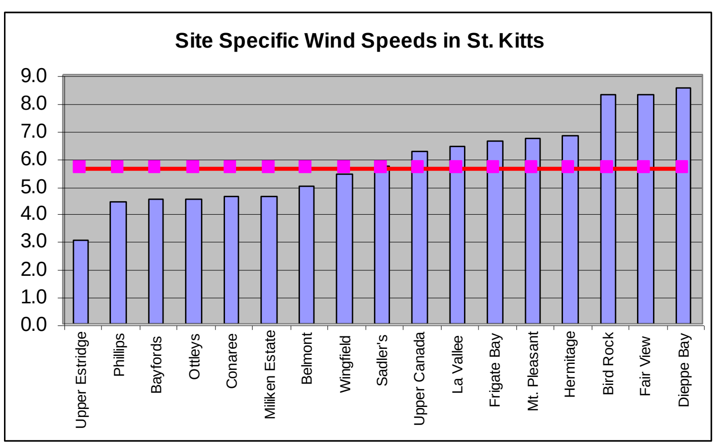


Figure 14 - St. Kitts Wind Speeds

- Wind speeds translate into energy production through considering the power curve of the wind turbines. The economic assessment of wind resources depends on the wind-determined hourly production in relation to the avoided cost for the hour. The graph below illustrates hourly production simulated for a wind project in Grenada over the course of a month:

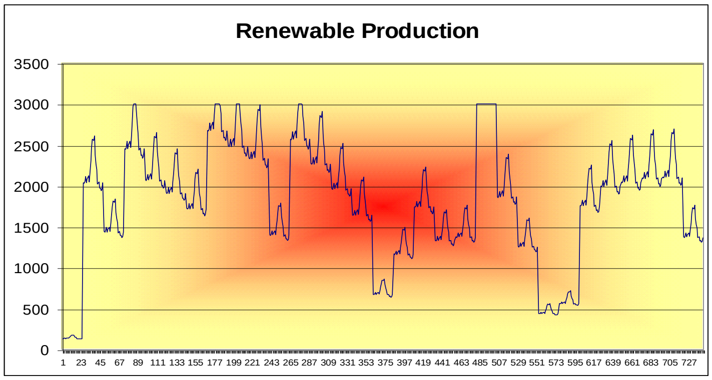


Figure 15 - Renewable Production

➢ Capacity Credits (Chapter 4)

The amount of avoided capacity cost for renewable projects is a complex issue that depends on the type of resource:

- For geothermal plants that do not have boiler breakdowns, the reliability of the plants should be higher than the reliability of diesel plants. This means that in comparing the addition of a geothermal plant with a diesel plant, the addition of the geothermal plant should lower the loss of load probability.

- Hydro plants are traditionally attributed capacity credit as a function of the energy production during low water years. A more appropriate method is determining the effect of hydro facilities on the level and the distribution of loss of load probability. The software provided to CARRICOM allows evaluation of renewable resources by adding capacity credit until the load of load probability is equivalent, whether or not the renewable project is added to the system.

- Biomass plants should have similar reliability as diesel plants. Therefore, the avoided capacity of biomass plants is the full amount of the plant.

- Wind and solar resources cannot be relied on to produce at their full potential when peak load on the system occurs. Therefore, the capacity credit of these resources will be less than the full capacity of the project.

Survey responses suggested that some utility companies will not allow wind projects to be given any capacity credit. However, the wind resources do have a positive effect on loss of load probability and in theory should be given capacity credit.

➢ Rate Impacts of Renewable Resources (Chapter 5)

Information provided in the annual reports of many utility companies in the region allows quantification of the rate and other economic impacts of adding renewable resources to various systems under alternative assumptions with respect to load growth, fuel prices, renewable resource assessments and the cost of renewable projects:

- The rate impact assessment depends on the business model used to develop projects. If independent private development with project finance projects are used and rates are set to avoided cost, there is a danger that developers will earn excessive profits and the benefits of RET projects will not accrue to people in the region.

- If prices in purchased power contracts are set to the cost of project (the minimum PPA price), rate reductions can be significant from the addition of renewable resources. The graph below illustrates the potential for rate reduction from developing pipeline renewable projects in Dominica:

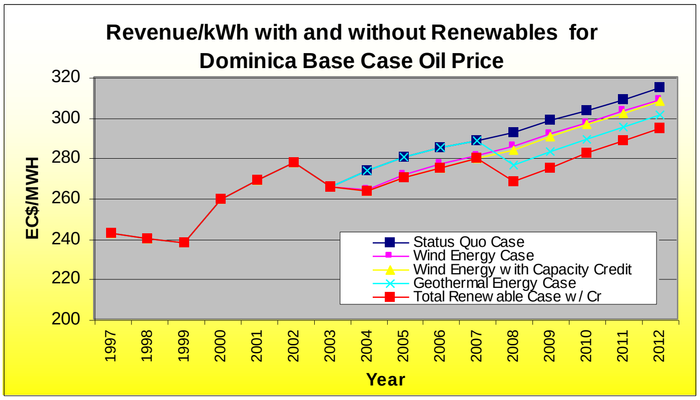


Figure 16

- The beneficial rate impacts of economic renewable resources are greater as oil prices move higher, load growth is increased, project renewable resources are greater, and the financing terms for renewable projects become more advantageous. This demonstrates that critical risks can be moderated through addition of renewable projects.

Resource Assessment

ADICA has reviewed the various resource assessment processes used for RET project in the course of its data gathering for its quantitative analyses. The specific economic effects with respect to different technologies are incorporated in the discussions of the analysis projects using those technologies. As to environmental effects, generally, the environmental benefits of using the output of RET projects reflect the displacement of a corresponding quantity of diesel generation – in particular, the elimination of CO_2 and other emissions associated with diesel generation.

The quantitative analyses revealed the importance of good resource assessments for certain technologies. For example, because the output of wind turbine generators increases roughly with the cube of the wind speed, small differences in wind speed assumptions can have large effects on project output and economics. Similarly, in the case of run of river hydro, the resource assessment would detail the required river flow data and how the river flows can be converted to ranges of hourly, monthly and annual generation – providing reliability and dispatch information for the buyer, and projected revenue flows for the lender.

Evaluation of Software Tools

ADICA reviewed the software tools currently used by CARICOM for screening analyses as well as other potential tools. CARICOM has used RETScreen and Proform to screen renewable technologies. The RETScreen model was effective in establishing a first cut at the economic viability of projects. Proform was less useful as a tool because of limited data. We also reviewed the HOMER model developed by NREL which evaluates benefits of renewable technologies on an hourly basis. The HOMER model has some added data features for modelling technologies. In evaluating geothermal, bagasse, and hydro technologies, we believe many of the projects are so site specific as to be difficult to evaluate with any screening model.

Final Report

This Final Report collects and organizes the results of the major component tasks of the project in a comprehensive product. The survey results, quantitative analyses, and template documents are compiled and presented as such in these volumes and in information memoranda for some pipeline projects. The body of the report also assembles lessons learned from our research on RET project financing approaches. The volumes of the Final Report include the individual project analyses, resource materials and data for future project developments, and materials collected during the project.

ADICA has tried to make this report and the results of our quantitative analyses accessible to non-technical stakeholders. Among other things, we have attempted to avoid the use of undefined technical terms or focusing too narrowly on technical issues. At the same time, because it is our intention that the report be useful to technical

professionals, we have retained the substantive content necessary for successful project development in discrete portions of our discussion and presentations of analytical results.

The Final Report also encompasses delivery of ADICA's software analysis tools under a perpetual license for CARICOM use. The software described (C++ code and spreadsheets) is made available without additional charge. The included software encompasses an hour-by-hour system simulation model, an integrated project finance model, and a utility financial model.

Capability Transfer

ADICA recognizes the importance of the CREDP objective of developing in-house and regional capabilities for conducting economic analyses independently in the future. ADICA strongly supports that objective, and in that connection, proposes an additional project activity that would provide training in conducting quantitative analyses like those we present in this report, using the software. In this additional stage of an extended consultancy, ADICA is prepared to organize training courses for regional professionals on conducting feasibility analyses of renewable projects in the region. Both CARICOM and CARILEC professionals, as well as other stakeholders, including utilities who have expressed interest in such training, could participate.

The courses could use renewable projects in the CARICOM pipeline as instructional case studies. Such an instructional initiative could include generation planning and modeling, avoided costs analysis, rate impact analysis, benefit costs analysis, project finance modeling, structuring of project finance deals, and risk management issues. At the end of the course, participants would be able to complete an analysis for any of the member nations and for any type of renewable technology.

Recommendations

The primary objective of our work has been to provide technical tools to assist in development of renewable resources in the Caribbean. However, our research has led to some recommendations for CARICOM and other key policy makers:

- With new capabilities and tools in hand, CREDP can be more assertive in assisting RET project development, looking for ways to share the unique resources it commands. The regional information and sophisticated tools CREDP now controls have real value only when they are used.

- When RET projects are constructed, local utilities and governments should work to assure that economic value is retained in the country, instead of being shifted from foreign fuel suppliers to foreign RET suppliers through PPA prices that are far above prices required for developers to earn adequate returns.
- RET project construction should include, whenever possible, training for local technicians, so that O&M contracts and future construction contracts can be

performed by local firms, retaining domestically more of the new economic activity attributable to RET projects.

- The initial costs of development, feasibility studies, and resource assessments are a significant part of the economics of plants. If CARICOM can provide funding for initial development, the economics of renewable technologies can be enhanced.

- The economics of renewable technologies can be enhanced by targeted tax holidays (since most RET equipment is foreign manufactured and imported), and by sovereign guarantees (reducing risk and insurance cost). These policies should be strongly encouraged by CARICOM for renewable projects.

Chapter II - Financing Alternatives

Introduction

This chapter presents a discussion of practical aspects of financing renewable projects in the Caribbean. In particular, it discusses the survey of regional financial institutions conducted as part of this consultancy and presents the questionnaire responses. The discussion also incorporates lessons of our academic and empirical research on financing strategies, conducted in the Caribbean and in other nations where renewable energy technologies are being developed. Annex 1, Annex 3, and Annex 4 include materials related to research for this chapter. Annex 1 contains the surveys developed for financial institutions; Annex 3 is a background discussion on project finance, and Annex 4 explains the survey process used in gathering information from financial institutions. Many of the conclusions in this chapter are from input received from stakeholders in the CARICOM region respecting the critical questions that define this project:

- What banks and other institutions in the region are willing to lend to renewable projects;
- What documents should be submitted by developers or utility companies to financial institutions;
- What loan terms (length, interest rate, etc.) could be expected from financial institutions;
- How do banks assess the risk of renewable projects;
- What collateral is required for loans;
- What can be the size of loans relative to the size of projects;

Through a set of surveys, we have attempted to identify those financial institutions active in the region that are genuinely interested in RET project loans so that project developers know where to go. Also, we have attempted to discern what financing terms a developer can reasonably expect to obtain from banks, insurance companies, and pension funds. The specific documents or presentation data for a new project will also be identified for the financial institutions.

The CARICOM survey objectives were defined, in part, by the results of earlier project work in this area. Those efforts revealed that while developers have a great deal of technical expertise and are effective in assessing alternative energy resources and technologies, their efforts to complete the development of alternative energy projects have been hindered by difficulties in obtaining private sector financing -- even for demonstrably economic projects. CARICOM, therefore, is endeavoring to lower barriers to private sector financing through a strategic approach that contemplates the following tasks.

(1) Identifying financing sources that are realistically accessible to project developers, and providing that information to the alternative energy sector.

(2) Using information from financiers in the region to construct "template" transaction documents that can save time and effort for developers. Templates include "information or offering memoranda", "power purchase agreements", and "bank collateral packages", among others.

(3) Helping regional financial institutions become more familiar with alternative energy technologies and more comfortable financing such projects in the Caribbean.

Renewable energy projects are capital intensive developments that are characterized by long economic lives and high capital cost in relation to the operating cost ratios. Consequently, access to economic financing is crucial to their overall cost. For project financing to be cost-effective in the development of renewable technologies, debt repayment should occur over terms of ten years or more, and interest rates must be reasonable. The survey was designed to verify or to refute these tentative conclusions and to assess the availability of suitable financing.

Financial Institutions Survey and Responses

Background

The conduct of a survey of financial institutions that are active or that are located in the region was an integral part of our data and information gathering effort. The protocol for the survey centered on distribution to financial institutions in a position to assist the development of RET projects in the Caribbean. The purpose of the questionnaire for financial institutions was to document, using information from the financiers themselves, the current and potential structures of transactions in the region. We sought to investigate the general attitudes of financial intermediaries toward project finance, the financial institutions' requirements for PPAs or other documents as part of developer proposals of actual transactions, the willingness of financial institutions to provide construction loans, permanent financing, or lending for other arrangements. The specific steps taken in this effort were:

(1) Research existing transactions and pertinent reports prepared by various stakeholders;
(2) Development of transaction term sheet and preliminary model PPAs geared to promote financing of the transactions;
(3) Development of a questionnaire designed to elicit realistic financing alternatives for renewable resources;
(4) Follow-up to identify those financing alternatives that will best promote renewable resource development; and
(5) Evaluation of the research and questionnaire results to refine our preliminary

conclusions on the type of financing that should be pursued and the form of template documents.

The questionnaire attempts to elicit the reasons (from the lenders' perspective) why non-recourse financing is difficult, the minimum size of a non-recourse transaction that warrants devotion of the necessary resources to arrange the deal, what transaction features (such as support from multilateral agencies) could make non-recourse financing feasible, and whether alternative financing structures would be considered.

During the development of the survey, considerable attention was given to the procedures that would be followed to conduct the survey. We were independently advised by various professionals in the regional financial community that the manner in which financial institutions were approached for cooperation in the survey could be determinative of the responses we received (or did not receive) and of the candor in any responses. The final protocols implemented for the survey were developed through iterative consultations with different financial community contacts.

In our background research, we have found it helpful to distinguish (a) local project financings, those that can be funded by regionally based financial institutions, and (b) large, more complex project financings that may require a consortium of regional or international banks. (We use the term "project financing" to mean limited or non-recourse credit facilities that are secured by the output of the project and the project's assets.) We have concluded that for many renewable energy developments, local project financing can be an effective funding mechanism because of their modest size and because of the relatively low credit ratings of Caribbean countries. The distinction between financing mechanisms based on size or location is maintained in this discussion.

Large Project Financing Transactions

Large project financing arrangements can also involve export credit agency guarantees, political risk insurance, or other special terms, as well as borrowing from international financial institutions. The high costs of arranging such transactions – including fees for lawyers, bankers and consultants – severely burden transactions below $100-300 million. Our interviews also indicated that, even for large loans, a low credit rating for the project's host country can constrain a developers' ability to complete large financings.

One area investigated by the survey is whether development of competitive financing resources in the Caribbean requires the participation of international financial institutions. In areas like the Middle East and parts of Asia, Europe and Latin America, joint ventures and large project financing arrangements using international resources have allowed major electric projects to be developed. Renewable energy projects in the Caribbean enjoy a favorable economic environment -- high avoided costs and good renewable energy resources -- and could be attractive to international lenders.

Developers with projects in the CARICOM Pipeline have a mixed reaction to using local versus international institutions. Some developers are wary of using international financial institutions because of the small size of their transactions. (CARICOM's identified geothermal projects and biomass projects, for example, have estimated costs ranging from $20 million to $90 million.) Others want to use international financial institutions because local banks are perceived as charging high interest rates.

Smaller Project Financing Transactions

Local banks in the Caribbean have demonstrated an ability to handle, on suitable terms, relatively smaller project financing transactions, such as projects requiring up to about $30 million. For example, a wind farm in Jamaica that cost approximately $25 million was financed with a loan of about $16 million from a local bank (after accounting for grants that effectively reduced the project cost to $19 million, the leverage was 83%). Small solar water heating equipment and installations have been financed on a regular basis in some locales, but such loans are highly correlated with consumers' and local banks' familiarity with the technology.

Local financing may offer the prospect of loans without the high set-up cost and conditions attached to assistance from export agencies or special risk insurance that may be demanded by international lenders. However, local financing can bring its own conditions, which may be similar to those of international lenders. For instance, in the Jamaica wind farm project, government participation (through a sovereign guarantee) and a requirement for local developers were critical to the project financing. Local bank financing appears attractive for most renewable projects in the CARICOM pipeline, because of their relatively smaller size and the locations of the projects.

Other Financing Alternatives

Our research has revealed that under certain circumstances, financing arrangements other than bank project financing may be attractive alternatives. Supplier financing and support from economic development agencies can be accomplished for relatively small projects. For example, in the Dominican Republic, diesel plants for the developer's own use have been financed through loans from U.S. diesel suppliers (conditioned on multilateral agency insurance for political risks). In other cases, financing has been accomplished using conventional loans, rather than project financing as defined above. In yet another loan arrangement, a European utility financed a wind farm in Curacao, and the developers were able to supplement that financing through local tax incentives. Finally, development banks can offer significant assistance in financing a project (e.g., the Caribbean Development Bank and the Inter American Development Bank).

Survey Objectives

This section describes objectives of the financial institution survey. A description of the survey process is described in detail in Annex 4. The survey itself is included in Annex I. One key question to be answered through the survey is whether project financing can be obtained in Caribbean countries from private financial institutions and for various different types of projects, such as geothermal. The nature of the terms on which such financing may be available is an equally important line of inquiry. Among the specific information the survey seeks are the following data:

- financial institutions that would be willing to finance alternative energy projects;
- the right contacts at those financial institutions;
- whether the financial institutions lend in local currency, in USD, or in Euros;
- whether the financial institution requires government guarantees of any type;
- whether banks can arrange financing on a regional basis or do they face geographic operating restrictions that seriously curtail developers' options;
- whether regional financing is available for developers from other nations who may be more experienced in the involved technologies and project designs;
- the tenor of loans from interested and able financing institutions;
- minimum and maximum loans sizes;
- when in the development process developers should begin working with financial institutions;
- whether particular banks prefer to work as a single lending institution or as members of financing syndicates;
- whether fixed interest rate or variable rate financing preferred;
- the likely requirements for collateral packages; and
- the essential terms of off-take agreements (i.e., PPA's) supporting the loans.

Contact List

Our contact list of financial institutions in the Caribbean was developed from two sources: (1) contacts provided by Enid Bissember, a banking industry professional on the staff of the CARICOM Secretariat; and (2) a comprehensive review of debt information in utility company annual reports. The database was then culled to eliminate multiple contact points in a single financial institution and apparently distinct contacts that actually represent different points in a single merged or reorganized enterprise. Currently there are more than 30 financial institutions included in the database that include the name, country, source of information, primary contact (including e-mail and phone), and subsidiary institutions and notes. For all except 10 financial institutions, there are named contacts with e-mail addresses. A summary of the contacts developed for the financial institution surveys are shown in the table below:

Table 4 - Financial Survey Contacts

FINANCIAL INSTITUTION	PHONE	SOURCE	WEB
AID Bank	767 448 2853	Enid Bissember	
All-First Bank	410-244-4035	Annual Report	
Ansa McAl Merchant Bank		Enid Bissember	http://www.ansamcal.com/ansa_finance.html
Antigua Commercial Bank	268 481 4200/3	Enid Bissember	
Antigua Barbuda Investment Bank (not a subs.)	268 480 2700	Enid Bissember	
Banco Popular de Puerto Rico	+1 284 494 2117	Annual Report	
Bank of Antigua	268 480 5300	Enid Bissember	
Bank of Nova Scotia	(501-2) 77027	Annual Report	http://www.scotiabank.com/cda/content/0,1608,CID3_LIDen,00.html
Bank of St Lucia	758-456-6000	Enid Bissember	http://www.caribbeanonlineyellowpages.com/listings_6/6_category_B_3446.html
Barbados National Bank	246 431 5737	Enid Bissember	http://bdscham.com/business_page.cfm?MemberID=105
Belize Bank Limited		Enid Bissember	http://www.belizebank.com/
Caribbean Commercial Bank	246-431-2463	Prev. Consult.	http://www.ccb.ai/
Caribbean Financial Services Corporation	(246) 431-6400	Prev. Consult.	http://www.caribbeantiger.com/trc-cfsc.htm
Chase Manhattan Bank	+1 284 494 2662	Annual Report	
Citibank, N.A.	(876) 926-3270 ext 2263	Annual Report	http://www.latam.citibank.com/corporate/lajmco/english/global/kcont.htm
De Surinaamsche Bank	011 597 471100	Enid Bissember	http://www.cawe-caweb.com/businessinfo/Suriname.htm
First Caribbean	242 367 2500	Enid Bissember	http://www.firstcaribbeanbank.com/
First Citizens Bank	868 625 2893/6	Enid Bissember	http://www.firstcitizenstt.com/location/default.html
Guyana Americas Merchant Bank, Inc.	592-223-5193/4	Prev. Consult.	
Guyana Bank for Trade and Industry	592 226 8431-9/ 227	Enid Bissember	http://www.gbtibank.com/
Hakrinbank N.V.	597 477956	Enid Bissember	http://www.hakrinbank.com/filialen.html
National Bank of Industry and Commerce Ltd	592 225 0853	Enid Bissember	http://www.nbicgy.com/
National Commercial Bank Jamaica	876-935-2536	Enid Bissember	http://www.jncb.com
National Commercial Bank of Dominica	(767) 448 4401/3	Enid Bissember	http://www.ncbdominica.com/about/atm.htm
NCB GRENADA	(473) 444 2265	Enid Bissember	http://www.ncbgrenada.com/yourbank/branch.htm#ncnh
RBTT merchant bank	868 623 1322 X2353	Enid Bissember	
Scotia Bank (BVI) Limited	+1 284 494 2526	Annual Report	
St Kitts Nevis Anguila National Bank	869 465 2204	Enid Bissember	http://www.sknanb.com/contact%20us.htm
The Royal Bank of Canada		Enid Bissember	http://www.royalbank.com

A more complete listing including insurance companies, pension funds, and other regional institutions is included in Volume III.

Analysis of Survey Responses

<insert patsy russell's comments>

- Lessons Learned
  - Financial Institutions
    - Essentials (Must Haves and Unacceptables) from this perspective
    - What Works and Why
    - What Does not Work and Why
  - Developers
    - Essentials (Must Haves and Unacceptables) from this perspective
    - What Works and Why
    - What Does not Work and Why
  - Utilities
    - Essentials (Must Haves and Unacceptables) from this perspective
    - What Works and Why
    - What Does not Work and Why
- Project Financing Recommendations from surveys
  - Changes in template documents
  - Specific recommendations on approach

Chapter III – Models of Renewable Project Costs

Introduction

The work plan states that we will complete a project finance analysis for each of the projects in the CARICOM pipeline:

> "…a project finance model will be developed for individual projects. This model includes the capital cost, construction profile, fixed O&M costs, variable O&M costs, emission credits and other aspects of the renewable plants. The project finance model also includes financial complexities such as cash flow waterfalls, debt capacity analysis, break-even evaluation and other features. As with the market simulation model, the project finance software will be provided as part of the project. The project finance model will use financial criteria to consider cost benefit analysis from a societal perspective."

The project models described in this chapter accomplish a number of practical objectives for CARICOM and development of renewable resources in the Caribbean. First, the project analysis is the backbone for evaluating whether the projects are economically viable. Second, the analysis can be used to guide future policy decisions on tax, development grants for resource assessment, financing support, transmission costs, grants from equipment suppliers and so forth. Third, the project finance model outputs are integral parts of information memoranda, feasibility studies, and other presentation materials required for obtaining financing.

The project finance model will hopefully be a working tool that CARICOM can offer developers to assist in their development work. In addition, the database of projects can

Subsidies for Renewables in OECD Countries

In most countries where RET is being developed, the projects receive direct subsidies that are necessary in making projects economically viable. There is a saying in Europe that coal plants run on coal, gas plants run on gas and wind plants run on subsidies. In contrast, projects in the Caribbean are economic without government support The requirement of subsidies for wind projects is recounted in the Standard and Poor's write-up of the FPL Wind Financing:

Wind power is usually not economically competitive with mainstream natural gas-fired and coal-fired technology for power generation. The high installed cost of wind projects, often around $1,000/kW, well in excess of those of new natural gas combustions turbines, which run around $500/kW to $600/kW, depending on location. Wind power is able to compete on price due mostly to federal assistance in the form of Production Tax Credits (PTCs) for power generated by renewable resources. Production tax credits provide a direct reduction in income taxes computed on the basis of 1.8 cents per KWh, escalating over the life of the project. Even with such subsidies, however, wind power can still have disadvantages due to price and also to transmission issues. Wind power generation is intermittent due to variations in wind flow, and this can cause problems with transmission systems. Also, strong wind resources are often not located near population centers, which can require potentially costly transmission service.[1]

be continually updated and represent a working tool for CARICOM, utilities, and developers in more efficiently assessing renewable technologies.

Internal Rate of Return and Required PPA Price

The project modelling described in this chapter is a central component in addressing the issue of whether renewable energy projects are economically viable without subsidy support from Caribbean governments or from multilateral institutions. Two key outputs from the models include internal rate of return and minimum required PPA price. If a project is economically viable, then the internal rate of return is above the required hurdle rate. The minimum required PPA price is the price that just covers costs of renewable projects and provides a target hurdle rate of return. Inputs to the project finance model include the capital costs, operating costs and capacity factors of the renewable projects in the CARICOM pipeline.

Required PPA prices in project models can be considered fixed costs of renewable projects if the analysis is being considered from a utility company business model perspective. Economic viability can be gauged by comparing these "required prices" or fixed costs (for project viability) stated in $/MWH terms with the avoided costs also expressed in $/MWH. Avoided costs are derived either on an annual basis from the rate impact analysis (Chapter 5), on a more detailed hourly basis from the avoided cost analysis (Chapter 4), or from the survey of fuel clause tariffs performed earlier by CARICOM.

The aim of this chapter is to describe how the project models can be used in a practical manner by developers, utility companies, and other interested parties, to assess economic viability, and prepare information memoranda. Economic viability is the basis for addressing questions relating to whether renewable projects in CARICOM countries can be financed without guarantees; whether government subsidies should be instituted to support projects; whether rates can be reduced from promoting renewables; and how pricing in PPA's should be established. The project models form an important analytical component of information memoranda -- a comprehensive project finance model can be printed for each pipeline project for use as a component of offering memoranda. (The procedure for printing models for each project is documented in Volume II).

Economic Viability of Renewable Projects

In most regions of the world renewable projects cannot be financed and constructed without government support, as discussed in the above insert. Given the required subsidies in other areas of the world, utility companies and other stakeholders should naturally be skeptical as to whether renewable projects are economically viable on a stand-alone basis. Due to good natural renewable resources – sunlight, trade winds, water flow, bagasse resources and volcanic activity along with the high costs of running diesel plants in the region, the Caribbean may be a unique area of the world in terms of the economics of renewable energy. Indeed, if projects such as wind farms and geothermal

plants are economically viable in the Caribbean, the region would be unique in the world as an area where economic benefits occur without subsidies.

The high cost of energy from conventional sources combined with the existence of attractive renewable resources drives the economics of renewable projects and project finance models. This point is made as follows by John W. Whittingham: "Except for Trinidad, Tobago and Barbados, none of the islands in the Caribbean archipelago has an indigenous source of petroleum, and replacement of fossil fuel generation by generation from a renewable source like wind or water power would protect an economy from swings in electric power prices occasioned by changes in the world price for oil."[4]

Chapter Three Outline

The project modelling analysis documented in this chapter confirms that most projects in the CARICOM pipeline are economically viable on a standalone basis. Sections of the project finance modelling analysis include:

1. Objectives of the project modelling and the benefits of the modelling process to utility companies, bankers, developers and Caribbean governments.

2. Summary of results and describes the databases we have developed in the project modelling analysis.

3. A real world case study – the Wigton Wind Farm in Jamaica – that is used as a basis for considering certain detailed financing, transmission interconnection, construction, timing, development cost, tax incentives, and PPA contract aspects of renewable projects.

4. Key variables that affect wind projects in the CARICOM pipeline and other renewable resource projects including the resource assessments, capital costs of the projects, Dutch government grants, income tax aspects of projects, costs of transmission interconnections, PPA pricing structures, and financing of projects.

5. Project modelling of geothermal plants and hydro projects.

Binder Library Resources for Project Finance Modelling

The assumptions, data and background analysis that form the foundation for the project modelling analysis are documented in the "CARICOM Renewable Resource Library" that is contained in Volume III. This library comprises 27 binders that cover subjects ranging from analysis of wind farms to background articles on bagasse plants, to actual PPA contracts around the world. Each binder includes a number of articles, reports, data, contact data and interview results from our research and investigation. The contents of

[4] Case Studies In The Caribbean, Wind Energy System in the Caribbean

the binders are also available on CD's. Binders used in the project finance modelling analysis include Binders 20, 21, and 22 on Wind Case Studies; Binder 16 on Geothermal Plants; Binder 17 on Bagasse Plants; and Binder 4 on Information Memorandums.

Section 1: Objectives of Project Finance Modelling

The project model is intended to assist developers and/or bankers in the financing process and in the development of information memorandums or other financing documents. The objective is also to provide support for utility companies in developing fair prices for purchased power contracts when they negotiate with developers. In addition, the project finance model analysis presented below is relevant for governments in developing policy and laws related to renewable resource frameworks (e.g., tax policy for RET projects, government loan guarantees, utility services, etc.).

The project finance modelling analysis builds on earlier work performed by CARICOM in screening projects in the pipeline. The prior work used RETScreen and other tools to establish capital costs, resource assessments and operating costs for projects in the pipeline. The project finance model analysis described in this chapter uses these inputs along with a more detailed measurement of construction cost timing, transmission interconnection costs, development costs, government subsidies, tax rates and tax depreciation policy, financing aspects including the timing of debt and equity issues, alternative repayment structures, debt service ratio criteria, financing fees, and other items. The project financing analysis therefore translates pre-feasibility analysis to realistic financing analysis.

Three-Prong Analysis Approach

The quantitative analysis we performed contains three interrelated models, which examine the economic and financial viability of a project from three distinct perspectives. This three-pronged approach combines a project finance analysis, an avoided cost analysis, and a rate impact analysis. At one level, these components of our analysis provide the information critical to, financiers, developers and utilities, respectively. More accurately, each of the models provides data useful to each class of stakeholders, and together the models give a comprehensive picture of the project's economics, financing prospects, and benefits for the grid utility.

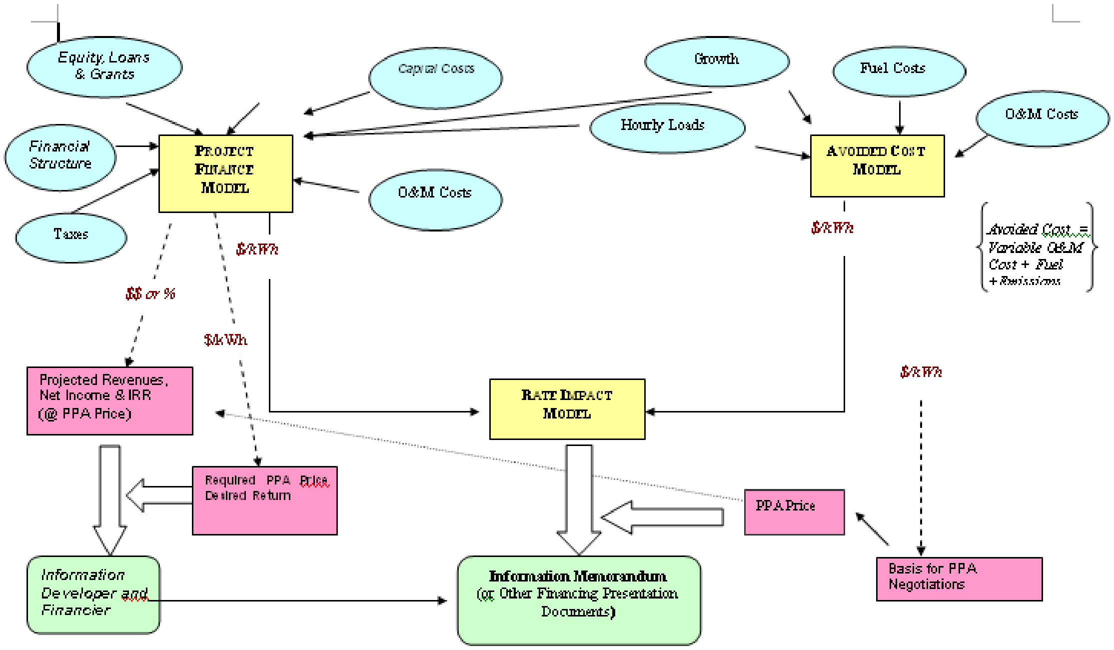
<u>Project Finance</u>. The project finance analysis in this chapter is the first step of the financial viability assessment. The analysis is performed using a software tool that models the economic characteristics of the project. Among the characteristics used as inputs are the project's capital costs, expected capacity factors, the anticipated structure and terms of financing, applicable, taxes, and other parameters. The analysis allows a developer to test the project's viability in the context of lenders' financing requirements, the local utility's avoided cost or the developer's own required return targets. For the developer, this model establishes the PPA price for the project's output that the developer must obtain to achieve its target return level. Alternatively, given a PPA price, the model

can determine the return that will be achieved, important information to potential sources of equity or loan financing.

Avoided Cost. The second prong of the analysis is an hour-by-hour avoided cost projection for the utility that owns the grid onto which the project's electricity output will be sold (where adequate data exist). This analysis considers grid operation factors such as plant dispatch, loss of load probability, and hourly renewable production. The analysis projects future dispatch of the project's generation to determine capacity values reliability impacts, and the costs avoided when the RET project displaces other generation. This analysis effectively defines the "price to beat" for the project's output to be attractive to the utility. This second prong of the analysis uses the required PPA prices determined in the project finance model (by using the developer's desired return level as a given) in evaluating economic viability. From the utility perspective, the analysis shows whether its grid system cost savings exceed the costs of acquiring replacement power and energy from the project through a PPA.

Rate Impact. The third prong of our analysis evaluates the effects of developing a particular RET project on the rate levels and financial position of utility companies connected to the project. This rate impact analysis uses PPA prices and estimates of variable costs (from financial data of utility companies) to evaluate how rates would change from using RET resources instead of conventional energy technology. The rate impact analysis compares future retail rates in a scenario that includes renewable resources to rates under a status quo case -- where no renewable resources are deployed. If the RET project is economically viable, it should be profitable for developers and, at the same time, reduce rates for utility companies and their customers. The rate impact analysis, which uses utility financial data, also provides "pro-forma" estimates of the avoided cost. The rate impact analysis uses average fuel and variable cost per MWH to measure the cost impacts of renewable resources. The model uses alternative financial criteria and historic financial statement data to project retail rates for various types of utility companies.

The graphic chart below provides an overview of the entire analytical process. It also sketches the flow of data and model results in the process.


Equity, Loans & Grants
Capital Costs
Growth
Fuel Costs
O&M Costs
Financial Structure
PROJECT FINANCE MODEL
Hourly Loads
AVOIDED COST MODEL
O&M Costs
Taxes
$/kWh
$/kWh
Avoided Cost = Variable O&M Cost + Fuel + Emissions
$$ or %
$/kWh
$/kWh
Projected Revenues, Net Income & IRR (@ PPA Price)
RATE IMPACT MODEL
Required PPA Price Desired Return
PPA Price
Basis for PPA Negotiations
Information Developer and Financier
Information Memorandum (or Other Financing Presentation Documents)

Use of Project Finance Models by Developers in Obtaining Financing

The project finance modelling analysis evaluates required PPA prices in the context of actual financing procedures. This is important because financing has been a limitation in renewable resource development. The project finance results constitute a major portion of the quantitative data needed for effective offering memoranda or other presentation documents that would be presented to bankers[5].

We believe the project finance models also can assist in expediting PPA price negotiations between developers and utility companies. For example, Mr. Vernon Lawrence of Grenada Electricity Services Ltd. discussed a desire to understand the business models of developers and their perspective. He mentioned the need for some basis upon which to set fair PPA prices that will not provide windfalls to developers and ultimately result in prices that are excessive for his own customers. He expressed an interest in seeing the results of the project finance model and gaining an understanding of the model. The discussion with Mr. Lawrence demonstrates why we believe one of the most important aspects of the project finance modelling will be providing a common set of assumptions and modelling mechanics for establishing PPA prices that are reasonable for both sides of the PPA contract.

Project Finance and Other Business Models in Economic Evaluation

The required PPA prices measure levelized prices required to develop a project and provide developers a pre-determined hurdle rate. If projects are developed by private utility companies or state-owned systems or even end-use customers, the required costs incurred to construct and operate a renewable project as a component of revenue requirements would be similar to PPA prices. This means that use of the project finance/PPA model can be regarded as a tool for economic evaluation under alternative business models. We emphasize that by developing project models, we are not advocating

Problems with the PPA Model Around the World

Systems where independent power producers (IPPs) have long-term traditional Power Purchase Agreements (PPA's) which typically feature 'Take or Pay' provisions (actually pay if available - taken or not) with state-owned entities underwritten by government guarantees have had major failures from a policy perspective. Examples of IPP/PPA systems that have not been sustainable include the models in Pakistan, Indonesia, Tanzania, Kenya and the Philippines. In various countries, the PPA prices were set at levels far higher than long-run marginal cost, the fuel contracts were flawed, the assumptions in the analysis were unrealistic, or there were corrupt dealings between developers and local officials.

[5] As part of our background research, we have obtained a number of information memoranda and other financing documents that illustrate how project finance models are used in presentations to the financial community. The information memoranda are included in Binder 4 of the library of background materials.

one particular business model. We recognize that there have been major problems around the world with the PPA/project finance framework -- see the accompanying text box. We emphasize that if a PPA system is used, transparency in the process is essential. We believe results from analytical models presented under alternative business models in this report should lead to a more transparent PPA evaluation and negotiation process.

Business Model for Renewable Analysis

Various different enterprise organization forms can be used in the development of on-grid renewable projects including small, private, independent generation companies who use project finance; utility ownership; joint-venture arrangements between local utility companies and overseas energy companies; independent generation using balance sheet (recourse) financing rather than project financing; lease financing by utility companies or independent producers; and other arrangements. Similarly, for off-grid projects, different business models can be applied such as vendor finance with leases; customer ownership; and utility company ownership. The appropriate business model depends on many factors including the tax law, regulatory policies, and project economies.

The cost and benefit approach described in this report is, to a large degree, independent of the business model. Benefits of renewable resources include reduced fuel cost, reduced capacity requirements, lower carbon emissions, and so forth. Costs include the fixed and variable expenses of operating projects and capital expenditures incurred to build facilities.

The benefit versus cost measurement may appear to require different analytical approaches that are dependent on the different business models. However, as explained below, the net economic benefits of renewable technologies depend to a far greater extent on resource assessment, avoided cost, capital expenditures, and other fundamental economic variables than the business model. For example, a utility company may use net value of revenue requirements in assessing benefits of a technology, while an independent developer may assess the internal rate of return earned on equity cash flow.

Differences in assessment of the value of a renewable project are caused by the different analytical methods only due to changes in net cost of capital and differences in risk allocation to alternative parties. For example, in a PPA agreement with an independent producer, risks of different wind speeds may be incurred by the equity investor rather than ratepayers. Similarly, if a utility business model is used to develop geothermal plants, risks of "dry holes" are incurred by customers rather than developers.

A few alternative analytical approaches are illustrated in the table below:

Table 5

Business Model	Analytical Approach

Utility Ownership	Net present value of revenue requirements for renewable technology as compared to non-renewable technologies, e.g., diesel.
Independent Power Generation	Net present value of savings in fuel, variable O&M, and capital (avoided cost) relative to costs incurred from paying PPA prices.
Off-Grid Vendor Finance	Net savings in fuel, O&M, capital, and losses relative to lease payments paid to vendor.

All of the analytical techniques can be boiled down to the same general formula – comparison of the avoided cost on the one hand with the fixed costs required to finance, operate, and maintain renewable technologies on the other hand. In any analysis, risks of resource variation, capital expenditure delays, cost of over-runs, and so forth must also be taken into account. Therefore, in the discussion of economic viability, when we use terms such as required PPA price, we are in no way limiting the analysis to a project finance business model. Rather, in the utility business model, the PPA price would represent fixed capital and operating costs that are part of the net revenue requirement formula. For example, in developing required PPA prices in this chapter, the sensitivity analysis on financing covers a variety of alternative business models and risk allocation schemes. The sensitivity analysis therefore incorporates a wide enough range to cover differences in cost of capital and risk allocation that occur from alternative business models. The avoided cost analysis in Chapter 4 assesses risks associated with the value of economic benefits that would occur in either a net present value of revenue requirement analysis or analysis of the merits of signing PPA contracts. Finally, the rate impacts computed in Chapter 5 would be similar irrespective of the business model applied (as long as the benefits are not collected as high levels of economic profit by foreign developers). Stated in another way, if the project works using project finance, it will also work using utility corporate finance.

Analytical Approach

The analytical approach in the project model is to derive either the equity IRR or the minimum required price from capital cost, operating cost, financing, tax, and (in the case of the IRR output) PPA price assumptions. To explain the model, we first describe the process for computing equity IRR assuming the PPA price is set by the avoided cost. Next, we describe the process for computing minimum PPA prices assuming that a target IRR on equity is given.

The project modelling can be described in terms of a set of formulas for the construction period and a set of formulas for the operation period. The minimum PPA prices and target IRR statistics are a function of free cash flow and equity cash flow. A representation of the equations in the models is as follows:

Equity Cash Flow = Equity Cash Flow in Construction Period + Equity Cash Flow in Operating Period

The equity cash flow can be derived from the free cash flow after financing cost as illustrated in the formulas below:

Free Cash Flow During Construction = Capital Expenditures – Development Costs – Cost of Reserves

Equity Cash Flow During Construction = Free Cash Flow – Debt Financing

Free Cash Flow During Operation = PPA Revenues – Operating Costs – Taxes

Equity Cash Flow During Operation = Free Cash Flow – Debt Service

Once equity cash flow is derived, the equity IRR and the minimum PPA price are established as below:

Equity IRR = IRR on cash flow assuming given PPA price (from avoided cost)

Minimum PPA Price = PPA price such that equity cash flow produces IRR target

Section 2: Summary Results and Project Finance Model Database Description

This section presents results of the project finance models for various cases and a description of the databases that we have assembled in the development of the project finance models. We first present results for the Grenada Wind project using alternative assumptions from the parameter database. Next, we show results for selected projects in the CARICOM pipeline for two cases with different financing and grant assumptions. The tables below show that required PPA prices are generally below avoided cost, particularly if advantageous financing (high debt leverage, long debt tenors, and low interest rates) can be obtained. Complete modelling results for the pipeline projects similar to the Grenada Wind presentation are included in Volume II. Each presentation of a project model incorporates two approaches for evaluating the feasibility of various projects in the pipeline as was discussed above:

Approach 1: Measure the return to investors -- the equity IRR -- assuming a given avoided cost as the basis for a PPA price.

Approach 2: Measure the required PPA price (or levelized cost) given a specified target return.

Through applying these two approaches we have implicitly incorporated both a project finance business model and a utility ownership business model in the analysis. The project finance model is represented by measuring returns given PPA prices (approach 1) while the utility business model is represented by the minimum PPA approach (approach 2).

Pipeline Database

The project finance model has been developed so that one can easily test multiple projects and different economic assumptions. To evaluate a new project, one simply enters the project name and project-specific data. The capital cost, the capacity factor, the timing of construction, the plant life, the development cost and other items are the data used in the model. We have labelled data on individual projects as the "pipeline database." Outputs from the modelling of each project are included in Volume II. In addition, Volume II includes an explanation of how to modify inputs, including how to add or delete projects. The pipeline database for wind projects, geothermal projects, hydro projects and biomass projects is shown in the tables below. The table does not include off-grid projects in the pipeline because these projects are modelled using a different customer financing approach.

Table 6 – Pipeline Database: Wind

		Wigton	Antigua Wind	Barbados Wind	Dominica Wind	Grenada Wind	Guyana Wind	Nevis Wind	St. Lucia Wind	St. Vincent Wind
Basic Assumptions										
Commercial Operation Date	Date	1/1/2005	1/1/2005	1/1/2005	1/1/2005	1/1/2005	1/1/2005	1/1/2005	1/1/2005	1/1/2005
Plant Life	Years	20	20	20	20	20	20	20	20	15
Income Tax Rate	Percent	36%	40%	40%	25%	30%	35%	38%	33%	30%
Capacity	kW	20,700.0	2,000.0	6,000.0	3,000.0	1,200.0	9,500.0	3,250.0	15,000.0	700.0
Capacity Factor	pct	33.8%	27.0%	34.5%	42.8%	36.6%	33.8%	27.1%	30.9%	36.0%
Capital Cost Assumptions										
Base Turbine Cost	$/kW	930.6	1,285.5	849.8	1,376.0	843.5	806.6	1,284.9	849.5	1,828.0
Foundation Roads and Installation	$/kW	147.2	62.5	67.5	161.7	35.0	79.5	153.8	97.7	
Transmission and Substation	$/kW	128.6	-	83.3	100.0	166.7	10.5	92.3	33.3	
Training, Commissioning and Contingen	$/kW	13.0	148.8	106.1	173.1	65.9	47.8	161.7	50.9	
Subtotal	$/kW	1,219.5	1,496.8	1,106.7	1,810.8	1,111.1	944.4	1,692.8	1,031.4	1,828.0
Construction Profile		Wigton	Wigton	Wigton	Wigton	Wigton	Wigton	Wigton	Wigton	Wigton
Fainancing Assumption		Input	Input	Input	Percent	Input	Input	Input	Input	Percent
PPA Price										
Initial Prices										
Base Real PPA Price		$ 50.51	85.8	55	100	72.6	52.8	90	69	85
Base O&M Price		$ 5.49	0	0	0	0	0	0	0	0
Operating Assumptions										
O&M per MWH		$ 12.00	12.17	11.24	11.73	19.97	12.27	14.74	10.98	12.00

Table 7 – Pipeline Database: Geothermal

		Dominica Geothermal	Grenada Geothermal	Montserrat Geothermal	Montserrat Geothermal	Nevs Geothermal	St Vincent Geothermal	St Lucia Geothermal
Basic Assumptions								
Commercial Operation Date	Date	1/1/2005	1/1/2005	1/1/2005	1/1/2005	1/1/2005	1/1/2005	1/1/2005
Plant Life	Years	20	20	20	20	20	20	20
Income Tax Rate	Percent	25%	30%	40%	40%	30%	30%	33%
Capacity	kW	12,000.0	12,000.0	4,000.0	5,000.0	4,000.0	12,000.0	10,000.0
Capacity Factor	pct	92.0%	90.0%	90.0%	90.0%	93.0%	93.0%	90.0%
Capital Cost Assumptions								
Base Turbine Cost	$/kW	2,500.0	2,083.0	1,500.0	2,000.0	1,500.0	2,083.0	2,000.0
Foundation Roads and Installation	$/kW							
Transmission and Substation	$/kW							
Training, Commissioning and Contingen	$/kW							
Subtotal	$/kW	2,500.0	2,083.0	1,500.0	2,000.0	1,500.0	2,083.0	2,000.0
Construction Profile		Level - 4 Year	evel - 4 Year	evel - 4 Year	evel - 4 Year	evel - 4 Year	evel - 4 Year	evel - 4 Year
Finaincing Assumption		Percent	Percent	Percent	Percent	Percent	Percent	Percent
PPA Price								
Initial Prices								
Base Real PPA Price		100	73	100	150	97	100	75
Base O&M Price		0	0	0	0	0		
Operating Assumptions								
O&M per MWH		12	20	15	15	24.78	10.00	15.00

Table 8 – Pipeline Database Hydro

		Belize Hydro	Guyana Hydro	Dominica Hydro	Barbados Off Shore Wind	Barbados Landfill Gas	Jamica Cogen	Belize Biogasse
Basic Assumptions								
Commercial Operation Date	Date	1/1/2004	1/1/2005	1/1/2005	1/1/2005	1/1/2005	1/1/2005	1/1/2005
Plant Life	Years	40	40	20	20	12	25	16
Income Tax Rate	Percent	20%	35%	25%	40%	40%	36%	20%
Capacity	kW	2,800.0	100,000.0	228.0	50,600.0	1,433.0	70,000.0	12,000.0
Capacity Factor	pct	44.8%	88.0%	45.0%	40.0%	69.0%	71.8%	75.0%
Capital Cost Assumptions								
Base Turbine Cost	$/kW	1,250	2,120	3,704	2,000	1,758	1,286	1,491
Foundation Roads and Installation	$/kW							
Transmission and Substation	$/kW							
Training, Commissioning and Contingen	$/kW							
Subtotal	$/kW	1,250.0	2,120.0	3,704.2	2,000.0	1,758.0	1,285.7	1,491.0
Construction Profile		Level - 4 Year	evel - 4 Year	evel - 4 Year	evel - 4 Year	evel - 4 Year	evel - 4 Year	evel - 4 Year
Finaincing Assumption		Percent	Percent	Percent	Percent	Percent	Percent	Percent
PPA Price								
Initial Prices								
Base Real PPA Price		60	52.8	97	55	55	60	60
Base O&M Price				0				
Operating Assumptions								
O&M per MWH		10.00	10.00	24.78	20.00	25.00	25.00	25.00

In the above tables, the construction profile refers to the percent of construction expenditures that occur in each month over the construction period. The construction profile titled "Wigton" uses percentages derived from the Wigton project, while the profile titled "Level-4 Year" applies equal percentages in each month over a four year construction period. The financing assumption – percent on input – refers to whether

specific financing assumptions are input in different periods (input), or whether the same percent applies to all of the construction.

Parameter Database

The economics of projects and required PPA prices depend on a number of financial, tax and other parameters. We have structured the project finance model so that each project can be evaluated against a variety of different parameters through a parameter database. A portion of the parameter database is illustrated in the table below. The actual database used in this report has 28 parameter scenarios.

In the parameter database, various rows have the following meaning. The construction profile defines how the capital expenditures are made over time; the initial price in a PPA can be split into two components as per PPAs in Jamaica with an O&M component and a base component; and the financing assumptions can be input to tie to the pattern of construction expenditures (input) or assumed on a single percentage basis.

![Adica Consulting logo]

Table 9 – Parameter Database

	Base		Base	Development Cost Included	Longer Construction Period	No Grant on Wind Generator	Higher Capacity Factor	Lower Capacity Factor	High O&M Cost and Inflation
Income Tax Assumptions									
Tax Holiday Assumption	-		-	-	-	-	-	-	-
Grant Percent Applied	0%		0%	0%	0%	0%	0%	0%	0%
Tax Depreciation Method	Straight Line Depreciation Rate		Straight Line Depreciation Rate	Straight Line Depreciation Rate	Straight Line Depreciation Rate	Straight Line Depreciation Rate	Straight Line Depreciation Rate	Straight Line Depreciation Rate	Straight Line Depreciation Rate
Tax Life	25		25	25	25	25	25	25	25
Added Plant Life	-		-	-	-	-	-	-	-
Capital Expenditure Assumptions									
Development Cost and Financing Fees									
Feasibility, Development and Engineering Amount	300,000.00		300,000	300,000	300,000	300,000	300,000	300,000	300,000
Feasibility, Development and Engineering Percent	5.00%		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Up-front Fee Percent	1.00%		1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Commitment Fee Percent	0.50%		0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Bank Agent Fee and Other Loan Percent	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Fixed Legal and Other Fees	250,000.00		250,000	250,000	250,000	250,000	250,000	250,000	250,000
Capital Expenditure Timing		Profile							
Base Consturction Expenditures	Wigton		Wigton	Wigton	Level - 3 Years	Wigton	Wigton	Wigton	Wigton
Apply Parameter Assumption	FALSE		FALSE	FALSE	TRUE	FALSE	FALSE	FALSE	FALSE
Development Costs and Other Pre-Construction	1 Year		1 Year	3 Years	3 Years	3 Years	3 Years	3 Years	3 Years
Financing Fees and Closing	Last Month		Last Month	Last Month	Last Month	Last Month	Last Month	Last Month	Last Month
Transmission Cost Parameters									
Transmission Cost	-		-	-	-	-	-	-	-
Ower-ride Transmission Switch	FALSE		FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
PPA Assumptions									
PPA Inflation									
Base PPA Price	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
O&M Component of PPA Price	0.20%		0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Environmental Adder	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Equity IRR Target	20.00%		20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
O&M Assumptions									
Inflation in O&M Costs	0.00%		0.00%	0.0%	0.0%	0.0%	0.0%	0.0%	6.0%
Include Blade/Train Replacements	No		No	No	No	No	No	No	No
Over-ride O&M Switch	FALSE		FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	TRUE
O&M per MWH	-		-	-	-	-	-	-	15.00
Capacity Factor Addition/Subtraction									
Capacity Factor Increment	0.00%		0%	0%	0%	0%	7%	-4%	0%
Financing Assumptions									
Debt to Capital Assumption									
Debt to Capital for Construction	50.00%		50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Debt to Capital for Development Costs	0.00%		0.00%	0%	0%	0%	0%	0%	0%
Debt to Capital for Financing Fees	50.00%		50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Interest Rate									
Construction Interest Rate	0.00%		0.00%	7.50%	9.00%	9.00%	9.00%	9.00%	9.00%
Permanent Loan Interest Rate	9.00%		9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
Tenor of Debt	10.00		10	10	10	10	10	10	10
Re-payment Structure of Debt	Mortgage		Mortgage	Mortgage	Mortgage	Mortgage	Mortgage	Mortgage	Mortgage
Month of Equity Issue	-								
Reserve Accounts									
Months of Debt Service In Account	6.00		6	6	6	6	6	6	6
Interest Rate on Debt Service Account	3.00%		3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%

Results for a Single Project Using Different Parameter Assumptions

To illustrate results for the project finance model, we show results for a single project using different economic and tax assumptions. We selected the wind project in Grenada to illustrate the effects of the different variables. Using the avoided cost estimate of \$73/MWH, the project has positive value in all but two of the scenarios, as evidenced by an equity IRR above 15%, and a required PPA price below the avoided cost.

ADICA CONSULTING

Table 10 – Project Finance Model Results for Grenada Wind Project

Simulate		Case -->	Grenada Wind			Capactiy Factor		36.6%		PPA Inflation	2.00%	
						Plant Life		20		O&M Inflation	2.00%	
						Base Plant Cost/kW		1,045.17		Debt Repay	15.00	
	Avoided Cost	Equity IRR	Project IRR	Average DSCR	Minimum DSCR	PLCR	Minimum PPA Price	Price vs Base	O&M/Plant	Target IRR	Debt/Capital	Cost per kW Incl IDC
Base	72.60	15.00%	10.46%	2.08	1.78	2.40	$ 60.18		6.13%	15.00%	57.35%	$ 783.6
Base	72.60	17.09%	11.6%	2.27	1.93	2.61	$ 60.18		6.13%	15.0%	57.35%	$ 783.6
No Development Cost	72.60	14.09%	9.3%	2.13	1.82	2.46	$ 66.86	$ 6.68	6.13%	15.0%	50.51%	$ 777.4
No Grant on Wind Generator	72.60	11.93%	8.8%	1.78	1.54	2.04	$ 72.25	$ 12.07	6.13%	15.0%	59.16%	$ 1,087.1
Higher Capacity Factor	72.60	24.95%	16.2%	3.03	2.55	3.51	$ 48.23	$ (11.95)	8.64%	15.0%	57.35%	$ 783.6
Lower Capacity Factor	72.60	14.74%	10.3%	2.06	1.77	2.37	$ 65.22	$ 5.04	5.46%	15.0%	57.35%	$ 783.6
High O&M Cost and Inflation	72.60	17.63%	11.7%	2.26	2.10	2.58	$ 59.41	$ (0.77)	4.60%	15.0%	57.35%	$ 783.6
Low O&M Cost and Inflation	72.60	23.00%	15.1%	2.85	2.41	3.29	$ 46.28	$ (13.90)	1.84%	15.0%	57.35%	$ 783.6
High O&M Inflation	72.60	14.54%	9.9%	1.99	1.77	2.26	$ 65.47	$ 5.29	6.13%	15.0%	57.35%	$ 783.6
10 Year Tax Holiday	72.60	20.96%	14.5%	2.55	2.28	2.93	$ 55.28	$ (4.90)	6.13%	15.0%	57.35%	$ 783.6
25 Year Tax Holiday	72.60	21.84%	15.3%	2.75	2.30	3.19	$ 53.66	$ (6.52)	6.13%	15.0%	57.35%	$ 783.6
Accelerated Tax Depreciation	72.60	17.09%	11.6%	2.27	1.93	2.61	$ 60.18	$ -	6.13%	15.0%	57.35%	$ 783.6
5 Year Tax Life	72.60	19.66%	12.6%	2.34	2.00	2.73	$ 56.60	$ (3.58)	6.13%	15.0%	57.35%	$ 783.6
High Transmission Cost	72.60	17.98%	12.2%	2.36	2.01	2.72	$ 58.45	$ (1.73)	6.36%	15.0%	57.11%	$ 743.7
Longer Plant Life	72.60	17.58%	12.6%	2.22	1.89	3.05	$ 58.44	$ (1.74)	6.13%	15.0%	57.35%	$ 783.6
3% PPA Inflation	72.60	17.84%	12.2%	2.37	1.93	2.76	$ 58.42	$ (1.76)	6.13%	15.0%	57.35%	$ 783.6
15% Environmental Adder	72.60	21.33%	14.1%	2.67	2.26	3.08	$ 52.33	$ (7.85)	6.13%	15.0%	57.35%	$ 783.6
12% IRR Target	72.60	17.09%	11.6%	2.27	1.93	2.61	$ 54.18	$ (6.00)	6.13%	12.0%	57.35%	$ 783.6
18% IRR Target	72.60	17.09%	11.6%	2.27	1.93	2.61	$ 66.63	$ 6.45	6.13%	18.0%	57.35%	$ 783.6
75% Financing	72.60	18.44%	11.5%	1.98	1.70	2.28	$ 58.17	$ (2.01)	6.13%	15.0%	65.50%	$ 787.3
60% Financing	72.60	16.54%	11.7%	2.44	2.08	2.82	$ 61.16	$ 0.98	6.13%	15.0%	53.29%	$ 781.8
9% Interest Rate	72.60	16.07%	11.6%	2.05	1.80	2.33	$ 62.36	$ 2.18	6.13%	15.0%	57.34%	$ 790.6
8 Year Bond Life	72.60	14.87%	11.6%	1.46	1.27	2.56	$ 64.96	$ 4.78	6.13%	15.0%	57.18%	$ 783.9
Level Payments	72.60	16.20%	11.6%	2.34	1.55	2.57	$ 61.95	$ 1.77	6.13%	15.0%	57.35%	$ 783.6
No Debt Service Reserve	72.60	17.05%	12.1%	2.11	1.84	2.40	$ 60.44	$ 0.26	6.13%	15.0%	57.84%	$ 789.8
Worst Case Financing	72.60	13.64%	11.4%	1.35	1.03	2.24	$ 68.25	$ 8.07	6.13%	15.0%	57.18%	$ 791.0
High PPA Price	72.60	8.83%	8.0%	1.32	0.96	1.69	$ 82.43	$ 22.25	6.36%	15.0%	58.98%	$ 1,055.9
Low PPA Case	72.60	23.59%	16.8%	2.94	2.36	3.96	$ 49.87	$ (10.31)	6.13%	15.0%	57.80%	$ 782.9
Base PPA Case	72.60	16.52%	13.6%	1.46	1.36	2.55	$ 74.10	$ 13.92	6.36%	20.0%	56.93%	$ 755.4

The first column in the table above shows the avoided cost assumption for Grenada; the second column shows the resulting equity internal rate of return assuming that avoided cost is the basis for PPA prices. For example, in the base case, the rate of return on the project is 17.09% when an avoided cost of $72.60/MWH is used as the PPA price (corresponding to the RETScreen analysis). The debt service coverage ratio (DSCR) statistics show the ability to service debt given the avoided cost and financing assumptions. A ratio above 1.75 is generally sufficient to meet requirements of bankers. The minimum DSCR represents the lowest DSCR in any year of the analysis, and is also an important ration in financing. The PLCR represents the project life coverage ratio, which a coverage ratio over the life of the project uses present value concepts in developing.

The column titled "Minimum PPA Price" shows the PPA price that generates an equity rate of return corresponding to the target IRR. This applies the second approach described above where the PPA price is an output rather than an input. The table illustrates that the grant for the generator (from the Netherlands), the capacity factor, the O&M cost, and financing all change the required price significantly. The graph below illustrates cash flows that generate the rate of return in the base case.

The column titled cost per KW including IDC means cost of the project including interest during construction, but after accounting for the grants. The "price vs. base" column refers to the change in the required PPA price from the base case that results from the alternative assumptions. For example, in the scenario titled "No Grant on Wind Generator", it is assumed that the Dutch grant of 35% is not obtained. In this scenario, the minimum PPA price is $72.25/MWH as opposed to the base value of $60.18/MWH. This means the Dutch grant increases the PPA price by $12.07/MWH, which is shown in

the column "price vs. base". Finally, the last three scenarios represent a compilation of best case, worst cast, and base case assumptions. The graph below shows cash flows in a single case.

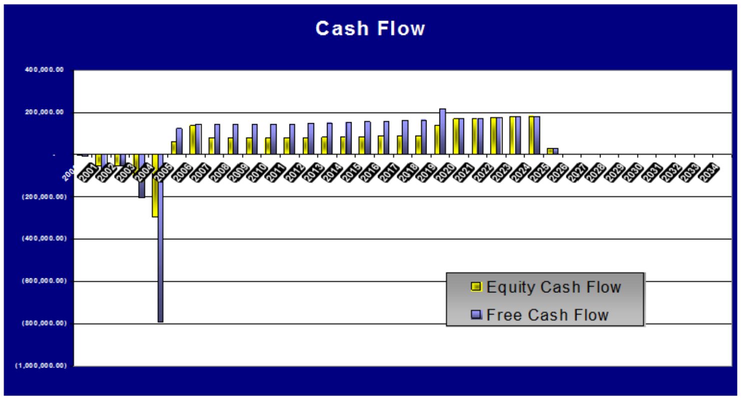


Figure 17 - Cash Flow

Results for Multiple Projects Using Common Parameter Assumptions

The project finance model can be run for a single project where multiple parameters are considered as discussed above, or across multiple projects with similar parameter assumptions for each project. In this section, we summarize results for different projects using similar economic parameters. Assuming no grants and 60% financing, the following table summarizes different PPA prices for projects in the pipeline. To assess economic viability, these prices are compared to the avoided costs derived from the rate impact model.

The table below illustrates that most of the projects in the pipeline are economic because the required PPA price is below the avoided cost. The column titled "price vs. avoided cost" subtracts the minimum PPA price from the avoided cost. A positive number means that the required prices are below avoided cost. Subsequent tables demonstrate similar results for the pipeline with different tax assumptions, debt financing assumptions, resource assessment assumptions, development cost assumptions, transmission cost assumptions, and foreign grant assumptions.

Table 11 – Alternative Pipeline Projects with Base Case Parameter Assumptions

Parameter Case Used: Base | Simulate

	Capacity Factor	Capital Cost/kW	O&M per MWH	Avoided Cost: $/MWH	Equity IRR	Project IRR	Average DSCR	Minimum DSCR	PLCR	Minimum PPA Price	Price vs Avoided Cost	O&M/Plant	Target IRR	Debt/Capital
Wigton	33.8%	1,206.44	$ 12.00	50.51	4.51%	4.70%	1.25	1.14	1.43	50.51		2.95%	15.00%	62.33%
Wigton	33.8%	1,206.44	12.00	50.51	4.51%	4.70%	1.83	1.71	2.11	77.70	(27.19)	2.95%	15.00%	62.33%
Antigua Wind	27.0%	1,348.00	12.17	85.80	8.19%	6.42%	1.93	1.70	2.21	105.70	(19.90)	2.13%	15.00%	60.88%
Barbados Wind	34.5%	1,000.67	11.24	55.00	8.91%	6.82%	1.89	1.66	2.17	63.51	(8.51)	3.40%	15.00%	61.76%
Dominica Wind	42.8%	1,637.67	11.73	100.00	21.92%	13.64%	1.78	1.54	2.04	71.62	28.38	2.69%	15.00%	65.00%
Grenada Wind	36.6%	1,045.17	19.97	72.60	11.93%	8.79%	2.01	1.73	2.31	72.25	0.35	6.13%	15.00%	59.16%
Guyana Wind	33.8%	896.63	12.27	52.80	9.73%	7.44%	1.88	1.64	2.16	57.66	(4.86)	4.05%	15.00%	61.98%
Nevis Wind	27.1%	1,531.08	14.74	90.00	7.06%	5.92%	1.90	1.67	2.18	115.57	(25.57)	2.29%	15.00%	61.61%
St. Lucia Wind	30.9%	980.53	10.98	69.00	13.83%	9.64%	1.87	1.64	2.15	64.23	4.77	3.03%	15.00%	62.20%
St. Vincent Wind	36.0%	1,828.00	12.00	85.00	4.64%	5.24%	1.92	1.69	1.89	104.07	(19.07)	2.07%	15.00%	65.00%
Dominica Geothermal	92.0%	2,500.00	12.00	100.00	25.15%	15.91%	1.92	1.66	2.21	60.99	39.01	3.87%	15.00%	65.00%
Grenada Geothermal	90.0%	2,083.00	20.00	73.00	15.99%	10.98%	1.92	1.65	2.21	62.79	10.21	7.57%	15.00%	65.00%
Montserrat Geothermal	90.0%	1,500.00	15.00	100.00	32.14%	19.21%	1.91	1.66	2.20	48.90	51.10	7.88%	15.00%	65.00%
Montserrat Geothermal	90.0%	1,500.00	15.00	100.00	32.14%	19.21%	1.91	1.66	2.20	48.90	51.10	7.88%	15.00%	65.00%
Nevs Geothermal	93.0%	1,500.00	24.78	97.00	31.51%	19.16%	1.92	1.63	2.21	54.51	42.49	13.46%	15.00%	65.00%
St Vincent Geothermal	93.0%	2,083.00	10.00	100.00	29.46%	18.04%	1.92	1.67	2.21	51.82	48.18	3.91%	15.00%	65.00%
St Lucia Geothermal	90.0%	2,000.00	15.00	75.00	19.09%	12.47%	1.92	1.66	2.20	57.26	17.74	5.91%	15.00%	65.00%
Belize Hydro	44.8%	1,250.00	10.00	60.00	14.09%	11.11%	1.80	1.52	2.70	56.03	3.97	3.14%	15.00%	65.00%
Guyana Hydro	88.0%	2,120.00	10.00	52.80	12.56%	9.81%	1.79	1.56	2.64	53.98	(1.18)	3.64%	15.00%	65.00%
Dominica Hydro	45.0%	3,704.21	24.78	97.00	0.00%	1.24%	1.93	1.67	2.22	191.17	(94.17)	2.64%	15.00%	65.00%
Barbados Off Shore Wind	40.0%	2,000.00	20.00	55.00	0.00%	0.00%	1.91	1.68	2.20	136.07	(81.07)	3.50%	15.00%	65.00%
Barbados Landfill Gas	69.0%	1,758.00	25.00	55.00	0.00%	-1.69%	1.67	-	1.85	80.68	(25.68)	8.60%	15.00%	65.00%
Jamica Cogen	71.8%	1,285.71	25.00	60.00	12.26%	9.19%	1.85	1.57	2.35	58.69	1.31	12.23%	15.00%	65.00%
Belize Biogasse	75.0%	1,491.00	25.00	60.00	9.72%	7.92%	2.03	1.72	2.08	60.71	(0.71)	11.02%	15.00%	65.00%

The above table demonstrates that some of the projects are economic and some are not economic, assuming no government grants. (In cases where the equity IRR is zero, the IRR cannot be computed because the cash flows are negative). Changing the assumption to include government grants, a tax holiday and more aggressive financing suggests that most of the projects are economic, as illustrated in the second table below.

Table 12 – Alternative Pipeline Projects with Advantageous Parameter Assumptions

Parameter Case Used: Base | Simulate

		Capacity Factor	Capital Cost/kW	O&M per MWH	Avoided Cost: $/MWH	Equity IRR	Project IRR	Average DSCR	Minimum DSCR	PLCR	Minimum PPA Price	Price vs Avoided Cost	O&M/Plant	Target IRR	Debt/Capital
	Wigton	33.8%	1,206.44	$ 12.00	50.51	12.02%	7.04%	1.57	1.48	1.57	50.51		2.95%	15.00%	70.63%
1	Wigton	33.8%	1,206.44	12.00	50.51	12.02%	7.04%	1.70	1.59	1.69	54.87	(4.36)	2.95%	15.00%	70.63%
2	Antigua Wind	27.0%	1,348.00	12.17	85.80	17.54%	9.46%	1.86	1.61	1.82	69.51	16.29	2.13%	15.00%	67.80%
3	Barbados Wind	34.5%	1,000.67	11.24	55.00	18.40%	9.62%	1.79	1.55	1.76	43.95	11.05	3.40%	15.00%	69.55%
4	Dominica Wind	42.8%	1,637.67	11.73	100.00	42.97%	18.36%	1.66	1.40	1.61	49.49	50.51	2.69%	15.00%	75.00%
5	Grenada Wind	36.6%	1,045.17	19.97	72.60	20.15%	11.54%	1.99	1.66	1.93	55.58	17.02	6.13%	15.00%	65.55%
6	Guyana Wind	33.8%	896.63	12.27	52.80	20.50%	10.72%	1.79	1.53	1.75	40.23	12.57	4.05%	15.00%	69.79%
7	Nevis Wind	27.1%	1,531.08	14.74	90.00	15.51%	8.54%	1.81	1.56	1.77	78.74	11.26	2.29%	15.00%	69.32%
8	St. Lucia Wind	30.9%	980.53	10.98	69.00	26.35%	13.25%	1.78	1.52	1.74	44.31	24.69	3.03%	15.00%	70.24%
9	St. Vincent Wind	36.0%	1,828.00	12.00	85.00	21.66%	9.19%	1.28	-	1.43	64.08	20.92	2.07%	15.00%	75.00%
10	Dominica Geothermal	92.0%	2,500.00	12.00	100.00	44.27%	21.69%	1.76	1.48	1.71	40.04	59.96	3.87%	15.00%	75.00%
11	Grenada Geothermal	90.0%	2,083.00	20.00	73.00	31.35%	15.58%	1.75	1.46	1.71	44.01	28.99	7.57%	15.00%	75.00%
12	Montserrat Geothermal	90.0%	1,500.00	15.00	100.00	52.74%	25.41%	1.73	1.47	1.70	33.62	66.38	7.88%	15.00%	75.00%
13	Montserrat Geothermal	90.0%	1,500.00	15.00	100.00	52.74%	25.41%	1.73	1.47	1.70	33.62	66.38	7.88%	15.00%	75.00%
14	Nevs Geothermal	93.0%	1,500.00	24.78	97.00	52.29%	25.47%	1.74	1.43	1.71	41.37	55.63	13.46%	15.00%	75.00%
15	St Vincent Geothermal	93.0%	2,083.00	10.00	100.00	49.85%	24.23%	1.75	1.48	1.71	33.65	66.35	3.91%	15.00%	75.00%
16	St Lucia Geothermal	90.0%	2,000.00	15.00	75.00	35.58%	17.36%	1.74	1.47	1.70	38.63	36.37	5.91%	15.00%	75.00%
17	Belize Hydro	44.8%	1,250.00	10.00	60.00	26.00%	14.76%	1.66	1.36	2.08	37.03	22.97	3.14%	15.00%	75.00%
18	Guyana Hydro	88.0%	2,120.00	10.00	52.80	23.53%	13.14%	1.63	1.39	2.02	34.65	18.15	3.64%	15.00%	75.00%
19	Dominica Hydro	45.0%	3,704.21	24.78	97.00	1.82%	4.80%	1.77	1.49	1.72	125.27	(28.27)	2.64%	15.00%	75.00%
20	Barbados Off Shore Wind	40.0%	2,000.00	20.00	55.00	0.00%	0.30%	1.73	1.50	1.70	84.90	(29.90)	3.50%	15.00%	75.00%
21	Barbados Landfill Gas	69.0%	1,758.00	25.00	55.00	9.93%	3.22%	1.11	-	1.36	53.10	1.90	8.60%	15.00%	75.00%
22	Jamica Cogen	71.8%	1,285.71	25.00	60.00	24.55%	12.96%	1.68	1.38	1.81	43.52	16.48	12.23%	15.00%	75.00%
23	Belize Biogasse	75.0%	1,491.00	25.00	60.00	25.16%	12.49%	1.45	-	1.56	44.77	15.23	11.02%	15.00%	75.00%

Section 3: Wigton Case Study

To explain the mechanics of the project finance model and the most important drivers of the analysis, we review the Wigton wind farm in Jamaica. Since this project is a renewable project in the region with completed financing and an established PPA, the project provides a reference point by which to evaluate other projects. (The developer of the project, Mr. Raymond Wright, is a past member of the "CREDP" project steering committee). The project has received significant publicity, and information regarding the

project has been published in the following documents included in the binder library that are publicly available (Binder 20):

- Wigton Wind Farm Project Design Document
- PPA between the Project and JPSCo (without prices)
- Environmental Impact Assessment of Wigton Wind Farm
- Statement of objectives for the Wigton Wind Farm Project
- Speaking notes on Grant Agreement for Partial Financing of Wind Turbines for Jamaica Wind Farm Ltd.
- News Release on the cost of the project

The Wigton wind farm is being developed by the Petroleum Corporation of Jamaica (PCJ), the state-owned oil company in Jamaica, and it involves building a 20 MW wind farm at the Manchester Plateau area, which is about 15km southwest of Mandeville, in central Jamaica. The project will utilize twenty-three 900 kW NEG-Micon turbines sourced from the Netherlands, with a component of grant financing from the Netherlands Government.[6] The project is expected to create 40 jobs during construction and 2 jobs during operation[7]. As evidenced by the public documents, the project is expected to be a model for the region.

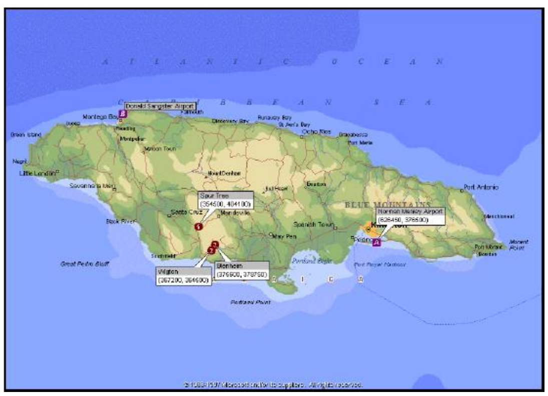


Figure 18 – Wigton Wind Farm, Jamaica

The average wind speed computed in monitoring the site was 8.4 meters per second, according to the project's environmental impact assessment. The project has a purchased power agreement with Jamaica Public Service Company, with an initial price of about 5.5 cents per kWh and a step-down of the price to about 5.0 cents per kWh in the fifth year of the contract. According to a presentation by KEMA, the avoided fuel and variable O&M for the project was $47/MWH, and the project was allocated avoided capacity of 7 MW or about 35% of the project capacity.

---

[6] Private Capital And Energy Markets, Raymond M Wright, Petroleum Corporation of Jamaica, 36 Trafalgar Road, Kingston 10, Jamaica, Email: raymond.wright@pcj.com
[7] Wigton Design Document, Binder 20.

The PPA pricing separated the operation and maintenance costs from other elements of the pricing and allows a charge of about .5 cents per kWh for the operation and maintenance[8]. In order to obtain a government guarantee on the loan for National Commercial Bank in Jamaica, the equity investment had to be 100% from a Jamaican owned company.

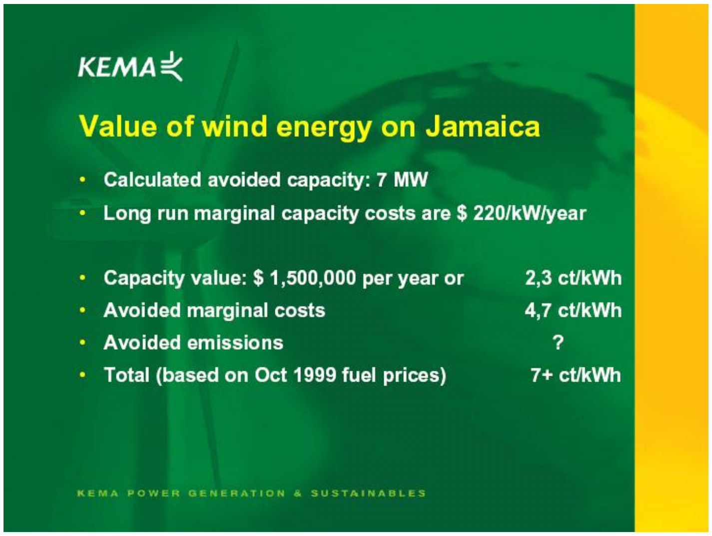


Figure 19 - Value of Wind Energy on Jamaica

Total installed cost of the project is $1,219 per kW. This cost is similar to many of the pipeline projects evaluated with RETScreen, as discussed in Section 4. Jamaica Public Service Company apparently mandated that the project pay substantial cost for interconnection -- $2.6 million -- as shown in the cost summary for the project below. The cost estimate does not include a provision for interest during construction and it does not include development fees, costs of a feasibility study, costs of an environmental impact assessment, costs of resource assessment or costs of financing, legal and other fees that generally would be incurred for a project of this type.

We have found moderately detailed data on a few other projects in developing countries. One example is the Tierras Morenas Wind Farm in Costa Rica using 750KW NEG Micon machines. This is a 24MW project with a cost of $35 million, or a cost per KW of $1,458. It had a long term PPA, and it secured $24 million in loans and grants from the Danish International Development Agency. The project had a fixed price turnkey construction contract. The Tierras Morenas wind farm produces 700,000 MWH, implying a capacity factor of 45%.

Key Drivers of Project Finance Models and the Wigton Case Study

This section works through input and output variables that form the basis of a project finance model, using the Wigton Wind Farm as a case study. We believe that by working

[8] Speaking notes of Phillip Paulwell, Wednesday 29, 2003

through the inputs and modelling process, we can illustrate how the modelling tool can be used by other developers.

The most significant outputs of the analysis are the return on investment for the sponsor (known as the equity IRR) and the amount of cash flow the project produces relative to the cost of the project (known as the project IRR). From the perspective of lenders to the project, the most important variable is the amount of cash flow the project generates relative to the amount of the payments for interest and re-payment of the loan. This is quantified by a ratio known as the debt service coverage ratio. In the discussion below, we work through the Wigton case study to derive these three statistics – the equity IRR, the project IRR and the debt service coverage ratio.

Using the data we have obtained for the Wigton project, we estimate a return to investors of 16.74% (the equity IRR). This is consistent with our experience with required returns for electricity project financings where target returns are generally around 15% (although the first project in a developing country is generally thought to require a 20% IRR).[9] By comparison, required returns quoted by developers in response to a CARICOM survey range from 15% to 20%.[10]

In the analysis below, we consider the factors that drive the economic feasibility and the return of the Wigton wind farm and other renewable projects. These drivers are capital costs of the project, timing of construction expenditures, resource assessment, operating costs, financing, government grants, tax treatment, and the realised capacity factor.

Financial Returns

Equity IRR	16.44%
Project IRR	7.18%
Equity to Capital at Close	17.2%
WACC	8.00%
Equity Cost	15.00%
Equity NPV	$157,092
Project NPV	($858,275)
Economic Plant Life	20
Income Tax Rate	36%
Tax Depreciation Life	20
Tax Carryforward Years	6

Debt Parameters and Outputs by Tranche

		Senior	Junior 1	Junior 2	Junior 3
Average DSCR		1.20	-	-	-
Minimum DSCR		1.02	1.02	1.02	1.02
LLCR		1.36	-	-	-
Interest Rate		7.5%	8.0%	9.0%	10.0%
Percent of Permanent Debt Financing		100.0%	0.0%	0.0%	0.0%
Debt Service Reserve Percent		7.1%	0.0%	0.0%	0.0%
Good Time Pre-payment DSCR		4.00	4.00	4.00	1.50
Bad Time Pre-payment DSCR		1.00	1.00	1.00	1.00
Ending Debt - Term		-	-	-	-
Ending Debt - Life		-	-	-	-
IRR on Debt		7.50%	0.00%	0.00%	0.00%
Initial Debt		16,837,447	-	-	-
Construction Financing:	2000	2001	2002	2003	2004
Percent Equity	17%	17%	17%	17%	17%

Figure 20 - Financial Returns/Debt Parameters

As with other parts of this chapter, in running the project finance model, we have applied two approaches. The first approach computes the return on investment given various

---

[9] Source: Interviews with bankers at investment banking firm Taylor De-Jongh.

[10] Please note that this is from public data and we have not reviewed the financial model used by PCJ or National Commercial Bank. We have made some assumptions with respect to items that we have not found definitive answers such as any special tax treatment.

ADICA CONSULTING

assumptions, including the PPA price. The second approach computes the required PPA price given the various cost and resource drivers and assuming a target return on investment (e.g. 15%) is achieved.

Key Driver 1: Capital Cost of the Project

Electricity generation from renewable resources is a very capital intensive endeavour. There are no fuel costs, and the operation and maintenance costs are generally relatively low, while the construction costs on a $/kW basis are high. Therefore, the first step in developing a project finance model is establishing the capital expenditures. Capital expenditures for the Wigton project include purchasing the equipment, installing the plant, paying for interconnection, and training personnel. The amounts are shown in the table below:

Table 13 - Wigton Capital Expenditures

		Cost/kW	Pct of Installation		Dollars
Base Turbine Cost	$/kW	930.60	100%	$	19,263,340
Foundation Roads and Installation	$/kW	147.20	16%	$	3,047,000
Transmission and Substation	$/kW	128.65	14%	$	2,663,000
Training, Commissioning and Contingencies	$/kW	13.04	1%	$	270,000
Subtotal	$/kW	1,219.49	131%	$	25,243,340

The costs shown in the above table do not include other significant cost items that must be incurred when developing a project. These additional costs include:

1. <u>The costs incurred by the developer in setting-up the project</u>

   PJC spent five years negotiating a PPA agreement; significant time and effort was undoubtedly spent arranging financing and a guarantee from the Jamaican government; the feasibility study had to be commissioned; the site had to be selected and so forth. These project development costs are site specific and can add 25% to the cost of the plant. We have found RETScreen useful in providing guidelines for the expected development feasibility study cost, resource assessment costs, and other costs of projects. These costs are documented in the RETScreen help menus.

2. <u>Costs of resource assessment</u>

   To estimate the wind potential of a project, site specific resource assessments must be made. Before the site is selected, a detailed wind mapping should be performed. With satellite data and modern computer tools, one can evaluate topography issues and do sophisticated optimisation. According to Australia Power and Water, using advanced computer programs, the cost of wind mapping is about $40,000 once a general area has been selected for study.[11] Once the specific site has been selected, a year's worth of wind data is necessary for the

[11] Source: Interview with Arthur Watts of Australian Power and Water.

feasibility study and the financing program.[12] This involves installation of a wind monitor which is generally a 40 meter tall tower. The tower costs $7,500 and the shipping costs are about $2,000. The towers can be installed with 3-4 people, and involves welding. Once the tower is up, costs of wind monitoring are about $300 per month. Including installation, the cost of monitoring is about $16,000 for a one year analysis. While this may seem like a small number for a large wind farm such as the Wigton project, for a 250 kW machine, the monitoring cost is about $102/kW.[13]

3. The legal and consulting costs associated with arranging financing

Legal and consulting costs can pose a significant problem for small plants because the costs are fixed. The point is made in the article written by Dr. Raymond Wright:

> "The first major step in any project is feasibility studies and these pre-investment costs, which include engineering, legal and financing fees, consultants, land access and permitting costs, are based mainly on time. Being inelastic in respect of project size, they have a greater impact on small projects. The development costs for renewables are spread over fewer units of output, and so the profit margin is lowered. Financial institutions, both multilateral, and foreign and domestic commercial, favour large projects because they offer lower transaction costs."

Costs incurred for development is a major reason we have created the template documents as part of this assignment. The potential benefits of a system with template documents are illustrated by development of small hydro in Australia. In this case, Barklays Bank financed a number of different projects using a program of template documents. There, the documents were the same for each plant. If a new plant was developed, there could simply be an addendum to the existing documents.[14] Another approach to reducing transaction costs has been used by Calpine in developing merchant plants. This approach is discussed in the case study presented in Binder 10.

4. Financing and underwriting fees

In financing a project, banks do not charge interest alone; they typically charge fees on the total monetary amount of their commitment in addition. For example, if no money is outstanding on a loan, but the bank agreed to lend $15 million in the future, a fee is charged on the $15 million. Banks also often charge for out of

[12] There are exceptions in Germany, where weather data from an Airport is sufficient.
[13] Source: Interview with equipment supplier
[14] Source: Interview with Steve Adlem: Australian Banker

pocket costs they incur for consultants and legal services. Rules of thumb used in project financing are that the financing fee is 1% of the loan, and the commitment fee is 0.5%.

5. Interest during construction

   The interest incurred on loans during the construction period which is recorded as a plant cost rather than an operating expense.

We have created a sensitivity analysis for the Wigton project where we included the estimates of developer costs, transactions costs and financing fees using the estimates referred to above (these costs are not in the base case). When these costs are included in the analysis, the return on investment declines from the 16.74% level described earlier to 10.99%. Using the second approach where PPA prices are adjusted to meet the target return, the base PPA price would be 5.5 cents per kWh, as compared to 4.9 cents per kWh in the case without the development costs assuming a 15% equity IRR is achieved.

Key Driver 2: Timing of Construction Costs

The timing as well as the amount of capital costs affects the viability of a project. If a large proportion of the expenditures are made well before the project goes into commercial operation, the return on investment can be lowered by a wide margin. For wind projects, once the project begins construction, the construction process is straightforward – the turbines are ordered and paid for, the foundation is laid, the turbines are trucked to the site and the project is tested and commissioned. Difficulties in the process may arise and planned timing may suffer if significant roadwork to the site has to be completed, or the turbines cannot be transported using, for example, existing transportation infrastructure. On the other hand, for geothermal plants, bagasse plants, and hydro plants, the construction period can be much longer, with more significant effects on project economics.

The timing of construction expenditures for the Wigton wind farm is illustrated in the graph below.

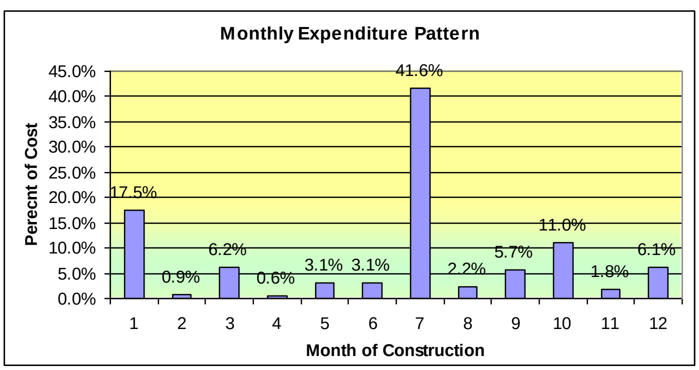


Figure 21 - Monthly Expenditure Pattern

To illustrate the impact of construction timing, we assume that costs for the Wigton project were spread over four years rather than one year. Such a delay would reduce the calculated return on investment from 16.74% to 13.6%.

Our analysis of the timing impact of development costs, feasibility studies, resource assessment costs, and other legal and consulting fees confirms the importance of reducing the up-front risky flows that are generally financed by the equity investors rather than by debt. If CARICOM can assist in the funding of these early development costs and reduce transaction costs (e.g., through providing template documents), the savings to developers would be significant.

Key Driver 3: Resource Assessment

The economic feasibility of any renewable project will depend on characteristics of resources that can be exploited for electricity generation. For a wind project, it is the wind speed (meters per second) and the time at which various wind speeds occur over the course of a year. For a hydro project, the resource assessment involves determining the water flows that will be available to the plant. For a geothermal project, the resource assessment involves drilling and finding the heat sources or reserves of steam that can drive a turbine. For bagasse plants, resource assessments involve determining the available supply of bagasse that depends on growing seasons, substitute fuels (e.g., waste, wood, tires) and other factors. For a solar project, the resource assessment involves determining the available sunlight.

Resource assessments for wind are subject to debate with a wide range of different estimates. Some dramatically good results have apparently been realized in the Caribbean and some analysts question whether the good results can be replicated. The wind resource assessment is described in much further detail in the discussion of wind project modelling below and in the next chapter. Wind resources are driven by northeast trade winds which provide a relatively stable wind regime in the Caribbean. In a project finance model, the resource assessment is modelled as the capacity factor. Given capital costs and a PPA with energy prices, the capacity factor can significantly affect the financial results of a project. The Wigton wind farm is estimated to have a capacity factor of 33.8%. As explained below, this is relatively high by industry standards, but low compared to other wind projects in the Caribbean.

We illustrate the importance of the capacity factor by running two cases – one case in which the capacity factor is increased to 40%, a performance level mentioned as a feasible high number for off-shore projects in the UK.[15] We also ran a low case of 90% of the base case capacity factor that is used by the financial community to test the ability of a project to re-pay debt.[16] The high case and low case affect the return on investment in a significant manner. When using the higher capacity factor, the return on investment

[15] Source: Mr. Ahmed Irej Jalal, International Atomic Energy Agency, Vienna, Austria
[16] See the Florida Power and Light Standard and Poor's write-up (Binder 21).

increases from 16.74% in the base case, to 25%. Using the lower capacity factor, the return on investment declines to 12.11%. If the approach of adjusting the minimum PPA price (or levelized cost) is used rather than evaluating the return on investment, the required PPA price for an adequate return declines from 5 cents per kWh to 4.3 cents per kWh with the higher capacity factor. On the other hand, the price rises to 5.4 cents per kWh with the lower capacity factor.

The analysis of the Wigton project with different capacity factors demonstrates the importance of accurate and optimised resource assessments. One potentially valuable service of CARICOM to facilitate RET development is provision of a sophisticated program of wind mapping that would help identify wind farm sites and reduce the uncertainty with respect to the capacity factor. The importance of resource assessment data in project financing is described by Standard and Poor's in its review of the FPL wind project included in Binder 21: "The cash flow from each project depends directly on energy production that depends on the wind resource. The lack of long-term wind resource data at each of the sites introduces risk that pro forma energy production levels and thus cash flows may not be realized."

Key Driver 4: Operation and Maintenance Costs

A project finance model requires estimates for revenues, operating expenses and capital expenditures. The revenues depend on the capacity factor and the PPA prices. The capital expenditures are the construction costs described above. The final element of the analysis is the operation and maintenance expenses. These expenses are low relative to the other costs of developing a project. (We understand the Wigton project will have a contract with a supplier to perform the maintenance on a fixed price basis).

We have found a number of different O&M expense estimates for wind projects. For example, the Mr. Dennis Elliott of NREL suggested a rule of thumb of .37 cents/KWH for wind projects, while others used a percent of the installation cost of the turbine as a rule of thumb. A study by the U.S. DOE states that the average annual maintenance cost per year is 1.5% to 2.0% of the cost of the turbine. Using the installation cost of Wigton, this amounts to a range of $18.5/KW/Yr to $25/KW/Yr. Using the 33% capacity factor to convert from $/KW to $/MWH, the cost range is between 0.7 cents per KWH and 0.94 cents per KWH ($7/MWH - $9.4/MWH). According to another source, windpower.org, the cost of preventative maintenance ranges between $12,000 and $14,000 per year for a 750KW turbine. On a per KWh basis, maintenance is about 1 cent per KWh, or $10/MWH. Further, the windpower.org source suggests that maintenance expenses are expected to be low early in the life of a plant and increase with age. In the Wigton model, we have assumed the O&M cost is $12/MWH (1.2 cents/KWH) with no escalation. The escalation of the operation and maintenance component of the tariff is limited to .2% per year in USD. In RETScreen, the inflation is generally expected to be 3%.

In its analysis of wind power projects, S&P assumed major retrofits and a 15% increase in O&M costs as a sensitivity case. We have performed a sensitivity analysis on the Wigton

project with respect to the O&M costs. The low case assumes .37 cents/KWH without inflation, and the high case assumes 1.2 cents/KWH with an escalation rate of 3.5%. In the low case, the return on investment increases from 16.7% to 26.9%. Using the required PPA approach, the price is reduced to 4.1 cents per kWh. In the high inflation scenario, the return is reduced from 16.7% to 13.52%.

Key Driver 5: Government Grants

By using turbines constructed by NEG Micon, the Wigton project was able to secure a grant from the Dutch government that reduced the cost of the turbine by 35%. This means the Dutch government paid for 35% of the turbines. The grant was provided under the Dutch Development and Environment Related Export Transactions Programme that aims to promote employment and enterprise in developing countries.[17] This grant only applies to the cost of the turbine and not to the cost of the foundation, roads or transmission equipment.

We have investigated the process for securing a grant by contacting the Dutch government, as well as the Danish government. Grants are also available from the Danish International Development Agency to qualified import countries (less developed). Documents from the Dutch and Danish governments are included in Binder 11, including instructions on filling out relevant forms.

Description of the ORET/MILIEV Programme

The grants available from the Netherlands are abbreviated using the acronym "ORET/MILIEV"[1]. In 1993 the MILIEV Industry and Development Programme was set up with the aim of promoting projects with a positive environmental impact. The programme reduces costs to developing countries of eligible projects through the award of grants for the purchase of capital goods, services or works from the Netherlands. The annual budget for the programme is 104,369,000 Euros. The grant is normally 35% of the transaction as was the case for the Wigton project. In addition, products and services from the Netherlands should account for at least 60% of the transaction.

There are seven CARICOM countries on the list of eligible nations including: Belize, Cuba, Dominica, Grenada, Jamaica, St. Vincent & the Grenadines, and Suriname. A graph of GDP per capita for countries in the region that drives eligibility for the grant is shown below. St. Lucia, St. Kitts, Trinidad & Tobago, and Antigua have somewhat higher GDP per capita, and they are not on the list of eligible countries.

[17] Wigton Design Document, Binder 20

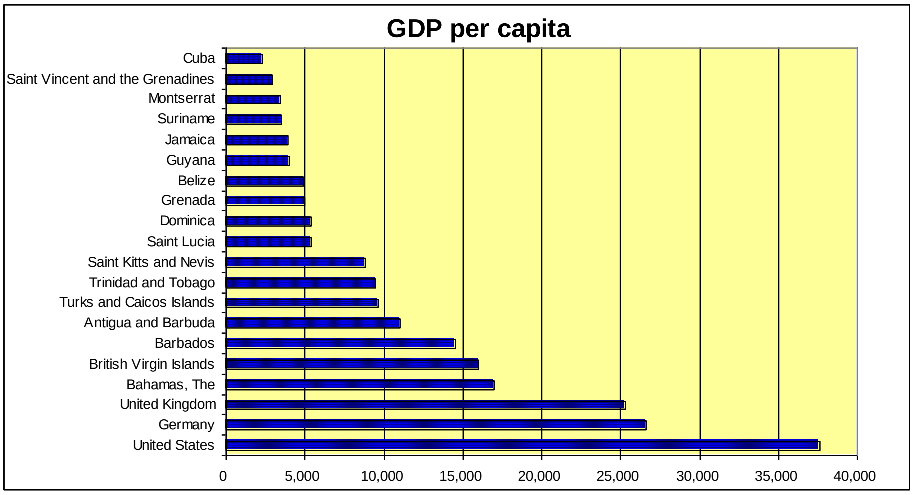


Figure 22 - GDP per Capita

To analyse the effect of the ORET/MILIEV grant, we have run the base case Wigton model with and without the grant. If the grant did not exist, the return on investment declines to zero. Using the approach where the PPA price is adjusted to yield a target return on equity, the PPA must increase to 6.4 cents per kWh to compensate for the loss of the grant (recall, the base case price was 4.9 cents/KWH). This analysis demonstrates the importance of equipment discounts in the form of grants or otherwise. CARICOM could consider working with governments to make sure grants remain available, or possibly secure grants for developments.

Key Driver 6: Taxes

In developing models of economic viability for renewable projects, we have used the perspective of a private developer, as well as an investor owned utility company. For these entities, taxes are a part of the cost of doing business and are generally considered in developing cost benefit analysis. (We realise that the GEF does not consider taxes as a part of project economics; however, in providing practical technical assistance to stakeholders, we have developed an after-tax approach mirroring the perspective of a developer). Capital intensive assets require significant amounts of investment. Since income taxes are on profits and investments require profit for private developers, the income taxes on a renewable project can significantly affect the economics of the project. The method of tax depreciation (sometimes called capital allowance), as well as the income tax rate, are the variables that have the most significant effects to private companies. Other taxes also can affect the economics of a project, such as property taxes and import duties. CARICOM has completed an extensive survey of taxes in the region, and we have recorded this data in Binders 5 through 8**.** Income tax rates, depreciation lives, capital allowance methods and property tax rates are shown in the table below:

Table 14 - Tax Rates

Country	Income Tax Rate	Property Tax Rate

		Rate	Base
Barbados	40%	0.95%	Market Value
Jamaica	30 - 33%	0.1 - 3%	Market Value
Trinidad and Tobago	35%	$10	Acre of Land
Anguilla	0%	-	-
Antigua and Barbuda	40%	7 - 14%	Rental Value
Dominica	30%	-	-
Grenada	30%	0.50%	Market Value
Montserrat	30%	1 - 2.5%	Market Value
St Kitts / Nevis	38%	$1 - $12	Acre of Land
St Lucia	33.33%	$0.25 - $1.00	Acre of Land
St Vincent	40%	5%	Rental Value
Belize	35%	Outside City 1% Inside City 3-8%	Market Value
Bahamas	0%	1 - 2%	Market Value
Guyana	35 - 45%	-	-

The effect of taxes on renewable resource development is referred to in the paper by Whittington:

> "Another barrier to the development of wind power in the region is the lack of clear cut Government policies on customs duty and tariff exemptions allowed to purchasers of wind turbine generators for private use. Most Governments will allow the duty-free importation of wind turbines on the basis that they contribute to a long term reduction in the demand for fuel oil, but none has enacted laws or regulations that make this explicit and automatic. It is left to the would-be purchaser to apply for the concessions on an individual basis".

Differences in tax policy are illustrated by the case of the Bahamas. The Bahamas has no income taxes, but there are import duties on electricity generation equipment of 17%. In running the Wigton base case, we assumed the general parameters above for Jamaica which include an income tax rate of 33% and a capital allowance method using sum of year digits depreciation. The data on the cost of the equipment itself suggested that there were no import duties on the construction equipment.

Alternatives with respect to income tax treatment are demonstrated by a wind farm being developed by Delta Caribbean in Curacao. The project received a tax exemption from the government. Because of the tax exemption, the project was financed with a lease from a utility company in Europe. Since the European utility, through the lease, is able to realize a tax deduction, it can pass on the tax savings through lower financing costs to the plant. Needless to say, such direct tax savings and indirect tax savings can improve the economics of the project.

We have tested the importance of the tax assumption by running two alternative cases for the Wigton project. In the first case, the project is assumed to have a tax holiday of ten

years and in the second case, the project is assumed to have a tax exemption for its entire life. With the tax holiday, the return is increased to 24% and the DSCR is increased to 1.35. Applying the approach of changing the minimum PPA price and holding the return constant, the price is reduced to 4.65 cents per kWh if the ten year tax holiday is assumed and the PPA price is reduced to 4.5 cents per kWh if taxes are eliminated for the life of the plant.

As with other key drivers, the analysis of income tax may suggest initiatives for CARICOM. First, developers can find the tax information for the various countries. Second, CARICOM could point the developers in the correct direction – who to contact and what to do -- to obtain tax exemptions, tax holidays or other beneficial provisions. Third, CARICOM may wish to ultimately work directly with governments to encourage tax incentives for renewable projects.

Key Driver 7: Transmission Costs

Transmission can be a significant component of the RET project's cost since special interconnection facilities are usually needed. Transmission components can include a field transformer, a substation at the wind farm and transmission lines to the grid[18]. Transmission costs of the Wigton project are estimated to be $2.6 million as illustrated on the table below:

Table 15 - Wigton Transmission Costs

Transmission and Substation					
	SCADA			$	43,000
	Grid Transformer			$	879,000
	Grid Connection Hardware			$	769,000
	Grid Connection Installation			$	769,000
	Sub-Station Installation			$	203,000
	Transmssion Subtotal			$	2,663,000

In analysing other wind projects, we have developed sensitivity cases with respect to transmission cost.

Key Driver 8: Plant Life and Residual Value

Project finance models generally extend through the PPA term, which in the case of Wigton is twenty years. After twenty years to twenty-five years, the turbines will probably not be operable and would have to be replaced. However, the roads used constructed to enable the power development, transmission interconnections, the land, and even the foundation may still have significant value. In the case of Wigton, these elements represent 12% of the cost. If they inflate the costs at one half of the rate of inflation over the 20 year project life, the residual value of the facilities would be $214/kW. We have created a sensitivity with respect to the project life whereby the

[18] Forces Behind Wind Power, Binder 21

residual is included and the life of the project is assumed to be twenty-five years instead of twenty years.

Key Driver 9: PPA Price

The most critical variable in the project finance model generally will be the price in the PPA agreement and the term of the agreement. The PPA contract allows a plant to be financed and it determines the return on investment. (In other chapters we are evaluating the avoided cost of utility companies in the region which should foster expedited negotiations between developers and utility companies). Setting PPA prices too high could ultimately be bad for development of renewable resources because of the perception that RET power is expensive.

The Wigton project obtained a 20 year PPA with Jamaica Public Service Company. The PPA did not have escalation in prices other than for the O&M component. To analyse the impact of PPA inflation assumptions, we have run an alternative case that assumes the price escalates at an inflation rate of 2.5% as was assumed in the RETScreen analysis. This analysis demonstrates that with escalation in the PPA price, the return on investment increases to 19.5%. If the return on investment target of 15% is used, the initial year PPA price could be reduced to 4.6 cents per kWh if inflation in later years is assumed.

Establishing transparent, objective ways to set PPA prices (e.g., avoided costs) can facilitate development of the renewable energy industry. If each project involved five-year negotiations, as was the case for the Wigton wind farm, many developers will not be able to make it through the negotiating process. Therefore, CARICOM can play an important role for development of renewable projects through providing data and analysis that allows different parties to become familiar with costs.

Key Driver 10: Financing

The final key driver of project finance models is the debt financing. Debt financing is critical to development of renewable resources in the region -- if a project can not obtain debt financing, it will not be developed. Variables that affect project economics include the amount of the debt financing, the interest rate on the debt, the repayment structure of the debt, and other provisions of the loan including the debt service reserve, covenants and provisions for maintenance reserves. Debt financing strategies are discussed in the Chapter 2.

The Wigton project was able to achieve an attractive financial package of two loans from the National Commercial Bank in Jamaica. The Wigton project was financed with a high percentage of debt financing (83%), a low interest rate (7.5%) and a reasonably long tenor of 15 years. These positive features were in part the result of the fact that the country of Jamaica guaranteed repayment of the loan – a sovereign guarantee. Through our surveys of financial institutions, we are investigating potential financing for renewable projects in situations without government guarantees.

The capital structure of the Wigton project is illustrated in the table below:

Table 16 - Wigton Capital Structure

Financing Summary		Dollars	Percent
Total Plant Cost	$	25,243,340	
Less: Other	$	152,021	
Net to Finance	$	25,091,319	
Less: Millev Grant	$	5,891,319	
Net Outside Capital Required	$	19,200,000	
PCJ Equity	$	3,200,000	16.7%
National Commercial Bank Loan	$	16,000,000	83.3%
Total Capital	$	19,200,000	100.0%

To illustrate the effects of debt financing on the project, we have developed a series of sensitivity analyses on the amount of debt financing, the interest rate, the length of the debt financing and the amount of required reserves. For instance, in one case, the debt financing percent is reduced from 83% to 60%. To demonstrate the effect of interest rates, the interest rate is increased from 7.5% to 9%. The effect of the debt repayment term is demonstrated by reducing the debt term to 10 years and increasing the debt term to 20 years. In the case where the debt term is increased to 20 years, a mortgage type re-payment structure is assumed. The reserve fund sensitivity is performed by changing the required size of debt service reserve funds.

The effects of different financing on the Wigton project on return on investment and the required PPA price are illustrated on the summary table below. The table shows that lower debt financing, higher interest rates, and shorter debt terms require higher PPA prices. The worst case financing scenario reduces the equity IRR to 9.06% and increases required PPA prices to 6.6 cents/KWH.

Summary of Sensitivity Analysis

The above discussion illustrated how various factors can significantly affect the rate of return and required PPA pricing. The table below shows which factors are most important from the perspective of the return on investment. The table begins with the base case described above. It then shows the effect of changing each variable. The graph demonstrates that the most important factor is the Dutch grant followed by financing, O&M, and capacity factor variation. Similar charts are shown for each project in the CARICOM pipeline as part of Volume II.,

Table 17 - Wigton Factors

Simulate		Case -->	Wigton			Capactiy Factor		33.8%		PPA Inflation	0.00%	
						Plant Life		20		O&M Inflation	0.00%	
						Base Plant Cost/kW		1,206.44		Debt Repay	15.00	
	Avoided Cost	Equity IRR	Project IRR	Average DSCR	Minimum DSCR	PLCR	Minimum PPA Price	Price vs Base	O&M/Plant	Target IRR	Debt/Capital	Cost per kW Incl IDC
Base	56.00	15.00%	6.92%	1.17	1.00	1.32	$ 49.11		2.95%	15.00%	83.61%	$ 880.7
Base	56.00	16.69%	7.3%	1.20	1.02	1.36	$ 49.11		2.95%	15.0%	83.61%	$ 880.7
No Development Cost	56.00	11.24%	6.2%	1.19	1.02	1.35	$ 55.27	$ 6.16	2.95%	15.0%	77.04%	$ 880.7
No Grant on Wind Generator	56.00	0.00%	4.1%	1.16	-	1.05	$ 64.94	$ 15.83	2.95%	15.0%	83.92%	$ 1,252.7
Higher Capacity Factor	56.00	35.26%	11.8%	1.53	1.35	1.75	$ 38.66	$ (10.45)	4.25%	15.0%	83.92%	$ 914.5
Lower Capacity Factor	56.00	9.89%	6.2%	1.07	0.91	1.23	$ 55.80	$ 6.69	2.60%	15.0%	83.92%	$ 914.5
High O&M Cost and Inflation	56.00	0.00%	2.6%	0.98	-	1.02	$ 59.86	$ 10.75	3.68%	15.0%	83.92%	$ 914.5
Low O&M Cost and Inflation	56.00	21.52%	8.9%	1.30	1.12	1.47	$ 44.93	$ (4.18)	1.47%	15.0%	83.92%	$ 914.5
High O&M Inflation	56.00	-4.18%	4.9%	1.18	-	1.15	$ 55.39	$ 6.28	2.95%	15.0%	83.92%	$ 914.5
10 Year Tax Holiday	56.00	19.98%	10.2%	1.25	1.01	1.42	$ 47.76	$ (1.35)	2.95%	15.0%	83.92%	$ 914.5
25 Year Tax Holiday	56.00	21.53%	11.1%	1.32	1.23	1.51	$ 46.66	$ (2.45)	2.95%	15.0%	83.92%	$ 914.5
Accelerated Tax Depreciation	56.00	14.91%	7.5%	1.18	1.01	1.34	$ 50.59	$ 1.48	2.95%	15.0%	83.92%	$ 914.5
5 Year Tax Life	56.00	19.54%	7.9%	1.21	0.83	1.38	$ 47.96	$ (1.15)	2.95%	15.0%	83.92%	$ 914.5
High Transmission Cost	56.00	14.94%	7.5%	1.18	1.01	1.34	$ 50.56	$ 1.45	2.95%	15.0%	83.92%	$ 913.8
Longer Plant Life	56.00	15.21%	8.5%	1.14	0.97	1.45	$ 50.27	$ 1.16	2.95%	15.0%	83.92%	$ 914.5
3% PPA Inflation	56.00	18.94%	9.1%	1.30	1.16	1.50	$ 46.59	$ (2.52)	2.95%	15.0%	83.92%	$ 914.5
15% Environmental Adder	56.00	24.38%	9.6%	1.35	1.17	1.54	$ 43.47	$ (5.64)	2.95%	15.0%	83.92%	$ 914.5
12% IRR Target	56.00	15.54%	7.6%	1.19	1.01	1.35	$ 47.30	$ (1.80)	2.95%	12.0%	83.92%	$ 914.5
18% IRR Target	56.00	15.54%	7.6%	1.19	1.01	1.35	$ 52.66	$ 3.55	2.95%	18.0%	83.92%	$ 914.5
75% Financing	56.00	13.18%	7.8%	1.31	1.13	1.50	$ 52.76	$ 3.65	2.95%	15.0%	76.06%	$ 910.5
60% Financing	56.00	11.03%	8.0%	1.63	1.44	1.86	$ 57.73	$ 8.62	2.95%	15.0%	60.98%	$ 903.8
9% Interest Rate	56.00	11.77%	7.4%	1.08	0.91	1.23	$ 53.63	$ 4.52	2.95%	15.0%	83.90%	$ 921.4
8 Year Bond Life	56.00	0.00%	7.2%	1.60	-	1.29	$ 60.36	$ 11.25	2.95%	15.0%	83.59%	$ 914.6
Level Payments	56.00	12.37%	7.4%	1.20	0.93	1.31	$ 53.52	$ 4.41	2.95%	15.0%	83.92%	$ 914.5
No Debt Service Reserve	56.00	14.57%	7.5%	1.37	-	1.22	$ 50.73	$ 1.62	2.95%	15.0%	84.80%	$ 921.2
Worst Case Financing	56.00	9.06%	7.7%	0.96	0.78	1.47	$ 66.10	$ 16.99	2.95%	15.0%	66.09%	$ 911.3
High PPA Price	56.00	0.00%	4.4%	1.55	-	1.19	$ 83.87	$ 34.76	2.95%	15.0%	66.10%	$ 1,247.5
Low PPA Case	56.00	30.59%	13.4%	1.45	1.24	1.93	$ 41.59	$ (7.52)	2.95%	15.0%	84.74%	$ 914.3
Base PPA Case	56.00	0.00%	8.6%	1.81	-	1.23	$ 66.62	$ 17.51	2.95%	20.0%	83.76%	$ 925.5

Section 4: Project Finance Models of CARICOM Wind Pipeline Projects

Introduction

This section builds on the Wigton case study and addresses project modelling of the numerous wind projects in the CARICOM pipeline. According to the U.S. DOE, "wind energy is generally the most economically competitive, widely available electricity source other than hydropower". The RETScreen documentation discusses the advantages of wind power for islands: "Regions that normally present the most attractive potential are near coasts or on the edge of bodies of water"[19].

In this section, we describe development project finance models for each project in the CARICOM pipeline. For these projects, we use the capital cost and resource assessments defined in the screening analysis and then we overlay the various "real world" project finance parameters using information from the Wigton case study. The project models of wind resources in the CARICOM pipeline can be used by developers in their information memoranda and in feasibility studies. In other words, project finance models described in this section represent a key component of the feasibility studies and information memoranda. Examples of information memoranda for renewable projects are included in Binder 4. This database of information memoranda is intended to be a tool for developers in developing their financing proposals.

In developing the pipeline database and the project finance models of individual projects, we have validated key assumptions in the model with background information that we have gathered from other sources. For wind projects, we have used the Wigton case

[19] Forces Behind Wind Power, Binder 21

interviews, and document research. Contacts in the interview process are described in Binder 24. The wind technology documents that support the analysis are included in Binders 20, 21, & 22. The next section describes background analysis and project finance models for pipeline hydro projects, solar projects, bagasse projects, and geothermal projects.

The project finance models include a number of sensitivity analyses for each of the projects. To illustrate how sensitivity analysis is used in actual financing, we present results from a large financing of multiple wind farms owned by FPL in the U.S. The table below illustrates how S&P evaluates wind projects using sensitivity analyses. The abbreviations P90, P95, etc. refer to alternative wind resource assessments.

Table 18 - DSCRs

Table 5 Project Base Case and Sensitivity Case DSCRs		
	Minimum (x)	**Average (x)**
Base case: P90 (1-year)	1.45	1.51
Base case plus P99 (1-year) every five years	1.31	1.47
P95 (10-year)	1.47	1.53
90% availability	1.24	1.35
15% increase in O&M: 2013-2023	1.36	1.47
Three-year major retrofit	1.45	1.51
P95 (10-year) + 15% increase in O&M 2013-2023	1.38	1.49
Standard & Poor's stress case: P90 (1-year average)	1.40	1.45

Summary of Results for Wind Projects

The initial RETScreen analysis did not include financing fees, costs of feasibility studies, costs of resource assessment, costs of consultants and lawyers, and costs of developing the project. As stated above, these costs tend to be subject to significant economies of scale, so the relative size of the costs is smaller for larger projects. To model the development cost, we have included a fixed cost of $250,000 for each project, and we assume other development costs to be 5% for the project. Other than the financing fees, we assume the costs are spread evenly for two years prior to completion of the project.

To model transmission costs, we substitute the amount of transmission fees in the Wigton case for the initial assumptions made in RETScreen. For all projects except the Grenada project, this raises the cost of the project. The impact of the development cost and the transmission raises the PPA prices significantly for specific wind projects as shown in the tables below. Clearly, any role CARICOM can play in (1) assisting with the development process; (2) shortening the negotiation period; (3) developing templates to streamline the process for small projects; and (4) working with utility companies to minimize the transmission cost would be valuable.

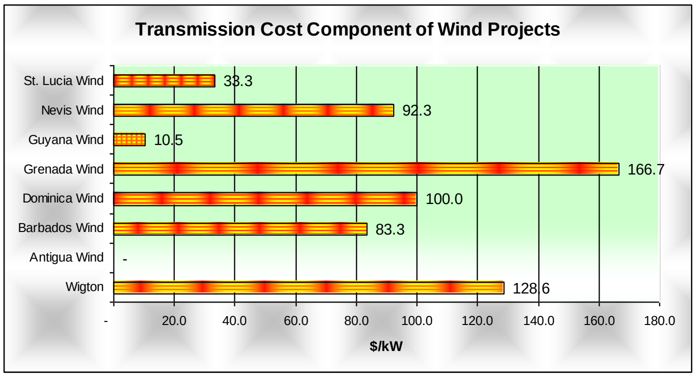


Figure 23 - Transmission Cost Component

In the RETScreen analysis, the resource assessments varied significantly between projects. These resource assessments were based on general weather data from the airports recorded by NASA. With actual site assessments, the resource assessment input can increase significantly depending on specific-site topology. To illustrate the effect of the resource assessment, we have increased the capacity factor by 10% and reduced the capacity factor by 10% for each project. Results of this analysis in the tables below demonstrate that CARICOM could provide a valuable service by assisting developers with data or tools for improved resource assessments.

The final sensitivity analysis on the CARICOM Pipeline database involves evaluating parameters related to debt financing. The Wigton project was able to achieve advantageous financing in part because it received a government guarantee. We have estimated parameters from the Econergy study and our preliminary discussions with financial professionals. The base case assumes debt leverage of 65%, a debt term of 15 years, an interest rate of 8.5% and a debt service reserve of six months. Financing sensitivity as shown in the table includes higher debt leverage and a lower rate, consistent with the Wigton case and a government guarantee. The high case assumes difficult financing conditions – an interest rate of 9.5%, leverage of 50% and a debt term of 10 years.

The next paragraphs describe the capital cost, resource assessments and operating costs of wind projects in the pipeline in light of our background research.

Capital Cost of Wind Projects

Capital costs estimated in the RETScreen analysis are reasonably similar to the Wigton project, as illustrated on the graph below, which compares the project cost per kW (including costs of the turbine, the foundation, the roads, transmission, and other contingencies) for the CARICOM pipeline wind projects. The installed costs range from $944 per kW to $1828 per kW and are a generally a function of the size of turbines assumed in the analysis. By comparison, the wind farms in Curacao had a cost of $1481/KW and $1667/KW.

![ADICA CONSULTING logo]

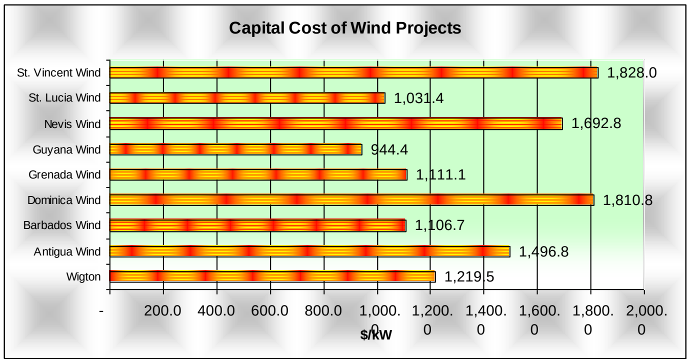


Figure 24 - Capital Costs of Wind Projects

The assumed wind turbine size was 250 kW for the projects in Antigua, Dominica and Nevis. For the project in Grenada, the turbine was assumed to be 600 kW, while the projects in Barbados and St. Lucia were assumed to use 750 kW turbines. Finally, the project in Guyana is assumed to use larger 950 kW turbines, similar to the turbines in the Wigton project.

To validate capital cost assumptions for new equipment, we contacted a number of equipment suppliers and developers. Brochures and information from 4 suppliers are included in Binder 19. Contacts for the various equipment suppliers are included in Binder 24. We believe that this contact list could be a valuable resource for RET developers and utility companies in the region. The contacts include suppliers of both the conventional large turbines and smaller turbines that may be required by special circumstances in some of the islands.

Capital Cost of Small versus Large Wind Turbines

One of the suppliers with whom we discussed the capital costs for wind turbines was Mr. Henry DuPont of Lorax Energy Systems. He has sold turbines in the Cayman Islands and has experience elsewhere in the Caribbean. Mr. DuPont emphasized the difficulty in delivering turbines and equipment to small Islands because of problems with trucks, cranes and problems with roads. The problem with large turbines is the required crane to install the turbines – the crane must have 450 ton capacity and be transported using nine tractor trailer trucks. Mr. DuPont stated that the cranes and tractor trucks do not exist in much of the Caribbean and the roads cannot handle the large trucks.

Because of the problems with transportation, Mr. DuPont asserted that smaller turbines of 30 kW or 100 kW are the only option for smaller islands -- a 120 kW machine requires a medium sized crane rather than a larger crane. He acknowledged that the cost of small turbines is significantly more than larger turbines. For a 100 kW machine, he estimated the installed cost is $2,600 per kW; for a 250 kW machine, the cost is $1,750 kW machine. By comparison, Mr. DuPont acknowledged that the installed cost of a 1 MW machine is about $1,200 per kW. This cost is consistent with the cost of the Wigton project described above. The towers for the smaller machines are made in Louisiana and relatively easy to deliver. For a 250 kW machine, the towers are 6.5 meters. Mr. DuPont estimated that with typical trade winds, the 250 kW machine should produce 1/2 million KWHs. This implies a capacity factor of 22.8%. He also stated that all machines -- ranging from 100 kW to 1 MW should have about the same efficiency and achieve similar capacity factors.

Another resource used in developing the capital cost of wind projects is the table from Dr. Raymond Wright's article shown below. The costs reported by Dr. Wright are lower costs than the RETScreen assumptions. The lower cost is consistent with comments made by Dennis Elliot of NREL, who suggested that installed cost including foundations, roads and transmission are as low as $700/kW for large machines. (The general rule of thumb is that the installed cost of a project is 1.35 times the turbine cost).

In discussions with equipment suppliers, we encountered some disagreement about the size requirement for turbines in the region. One regional RET developer stated that there was no real constraint on the size of turbines due to road conditions and the size of the load. However, one of the equipment suppliers (Henry DuPont) asserted that large turbines cannot be used on small islands without the infrastructure to move cranes and equipment. A summary of our discussion with Mr. DuPont is included in the accompanying box "Small versus Large Turbines".

Power Technology	Capital Cost ($/kW)
Wind	800
Bagasse	900 -1,300
Hydropower	1,000 – 4,500
Geothermal	1,000 – 4,000
Solar PV	2,000 – 7,500
Coal	1,300
Natural Gas	600
Nuclear	1,200 – 2,000
Oil	900 – 1,200

Resource Assessment of Wind Projects

The resource assessment for wind projects ultimately results in a capacity factor that is input to the project finance model. We have investigated expected capacity factors from a number of sources. As explained in our discussion above, there are questions relating to whether very high capacity factors can be achieved in the region. According to RETScreen documentation, "wind energy project capacity factors have improved from 15% to over 30% for sites with a good wind regime" (RETScreen Documentation, Binder 21). The RETScreen documentation also suggests that capacity factors above 35% are unexpected. However, a 58% capacity factor is reported by a wind farm in Curacao.

An example of typical capacity factors for wind projects taken from documentation of a large financing completed by FPL in the U.S. is shown in the table below.

Table 19 - Energy Production Forecasts

Project and Portfolio Energy Production Forecasts								
Site	LB II	CGordo	SW Mesa	Hancock	HWinds	New Mex	Montfort	Portfolio forecast
Rated power (MW)	103.5	41.3	74.9	97.7	145.8	204.0	30.0	697
Net energy (GWh/year)	333.0	104.5	231.8	288.5	476.5	536.6	57.6	2,029
Net capacity factor (%)	36.7	28.9	35.3	33.7	37.3	30.0	21.9	33

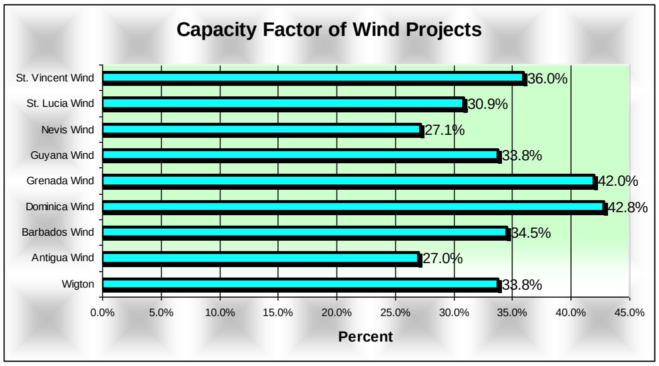


Figure 25 - Capacity Factor of Wind Projects in the CARICOM Pipeline

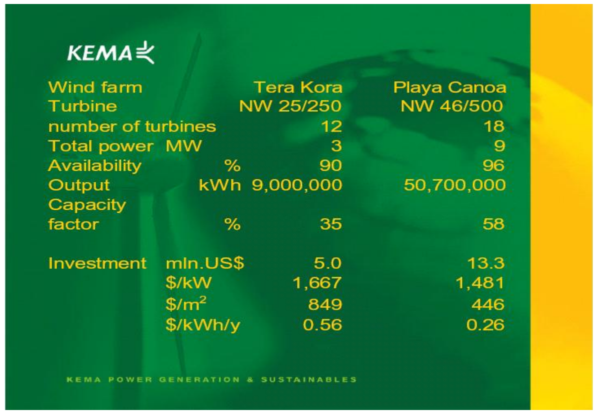
As demonstrated in the sensitivity analysis, the resource assessment is an important variable in determining the feasibility of a wind farm. The capacity factor is driven by wind speeds and the variability in wind speeds. If the wind speed was constant and the speed was sufficient to maximize the turbine output, the capacity factor would be 100%. If the wind speed is too fast, the generators trip off. At lower wind speeds, the generators produce less than their rated output.

Figure 26 - Turbine Comparison

The above figure illustrates significant differences of opinion and in estimates of the capacity factor of wind projects in the region. Roy Kolader of Delta Caribbean stated that he has been experiencing very high capacity factors, exceeding even the 58% capacity factor shown above.

Other Variables in Modelling Wind Projects

A number of other variables influence the economics of wind turbines, including construction time, project life, O&M, costs of grid stabilization, and other factors. The delivery time of a turbine is 7-8 months after the machines have been ordered. The expected life of the machines is typically estimated to be 20-30 years.


KEMA

Wind farm		Tera Kora	Playa Canoa
Turbine		NW 25/250	NW 46/500
number of turbines		12	18
Total power	MW	3	9
Availability	%	90	96
Output	kWh	9,000,000	50,700,000
Capacity factor	%	35	58
Investment	mln.US$	5.0	13.3
	$/kW	1,667	1,481
	$/m²	849	446
	$/kWh/y	0.56	0.26

KEMA POWER GENERATION & SUSTAINABLES

Figure 27 - Wind Farm Statistics

Some have suggested that turbines can cause problems with grid stability when wind produces 30% of the total load. The problem is that wind fluctuation can cause the diesel throttle to move up and down. One can rectify the problems of wind fluctuation with a variable speed compressor and a refractor. In addition, small variations in electricity production from wind gusts diminish with more (>2-3) units in a wind farm, since all units will not be affected simultaneously by the wind gust. If the wind load is less than 30% of electricity load, no special equipment is required. If the wind is 30 to 50 percent of load, the equipment to provide stable power will add $50,000 to the capital cost of a project. For systems where wind generation is 50-100% of load, the cost of additional equipment is $100,000 per turbine.

Section 5: Project Models of Hydro Power Plant, Geothermal Plants, and Bagasse Plants

Hydro Plants

Small hydro power is more difficult to evaluate than wind using screening models because of site specific factors. The capacity factor of hydro projects depend on the specific nature of water flows and the capital cost of the projects is highly dependent on the site. In the extreme, if a dam already exists or the river flows can support generation without a dam, the capital costs can be much lower than in cases where a dam must be installed. Countries with hydroelectric potential include Jamaica, Dominica, St. Vincent, Belize, Guyana, and Grenada. The CARICOM pipeline includes three hydro projects with costs of $1,250/KW, $2,120/KW, and $3,204/KW respectively. Capacity factors are estimated to be 44.8%, 88%, and 45%.

Hydropower is regarded as a mature and proven technology (even though the capital costs for its exploitation are relatively high in the region) so there is no difficulty attracting funds for resource assessments or project implementation. The table below taken from a World Bank database illustrates that many plants have been constructed in Latin America for $1,000/KW or less.

Table 20 - Project Statistics

Country Name	Project Name	Yr In Service	MW Capacity	Parent Name	Fuel Type	Total $	Cost per kW
ARGENTINA	Salto Andersen Generacion Hidraulica	1996	7	New World Power	HYDRO	8.5	$ 1,214.29
ARGENTINA	Hidroelectrica Pichi Picun Leufu	1997	261	Cia. Naviera Perez Companc	HYDRO	137	$ 524.90
BOLIVIA	Kanata Power Plant (Synergia)	1998	7.6	Synergia S.A.	HYDRO	4.9	$ 644.74
BOLIVIA	Hidroelectrica Boliviana (Central Taquesi)	2000	85.8	Tenaska International LLC	HYDRO	53.5	$ 623.54
BRAZIL	Energia Cassol	2000	10.6	Energia Cassol	HYDRO	4.4	$ 415.09
BRAZIL	Jauru Small Power Plant	2000	20	Agroindustrial Araputanga	HYDRO	16.6	$ 830.00
BRAZIL	Muniz Freire Hydroelectric	1997	25	Samarco Mineracao	HYDRO	25	$ 1,000.00
BRAZIL	Porto Estrela Power Plant	2000	112	Companhia Vale do Rio Doce SA (CVRD); Cote	HYDRO	59	$ 526.79
BRAZIL	Igarapava Hydroelectric plant	1994	210	Companhia Mineira de Metais; Companhia Sid	HYDRO	210	$ 1,000.00
BRAZIL	Cana Brava Hydroelectric Power Project	2000	450	Tractebel	HYDRO	426	$ 946.67
CHILE	Hidroelectrica Aconcagua SA	1992	72.59	Guardia Vieja SA	HYDRO	82	$ 1,129.63
CHILE	Rio Duqueco Hydroelectric	1996	118	Iberdrola SA	HYDRO	195	$ 1,652.54
CHILE	Electrica Alto Cachapoal	1997	195	Construtora Andrade Gutierrez; NRG Energy; Va	HYDRO	300	$ 1,538.46
CHILE	Empresa Electrica Pangue SA	1994	450	Endesa (Chile)	HYDRO	367	$ 815.56
CHILE	Ralco Dam	2000	570	Endesa (Chile)	HYDRO	560	$ 982.46
PERU	Yanango - Chimay Power Project	1998	181	Edegel; Perene Peruana de Energia	HYDRO	60	$ 331.49
							$ 886.01

Geothermal Project Finance Modelling

The next paragraphs describe how we have researched geothermal projects. We begin with introductory comments, and then discuss screening models, resource assessment, capital cost, and O&M cost. As described by a study included in the binder library, "Geothermal energy can be defined as heat that originates within the Earth. Resources tapped for electricity generation could provide energy for 50 years or more, but plant equipment typically reaches the end of its life before the resource is depleted"[20]. We have researched geothermal resource development by reviewing the earlier screening analysis performed by CARICOM, analysing data in the project pipeline, creating a library of background material, and modelling required PPA prices and equity returns for projects in project models. As compared with the earlier screening analysis, the project model incorporates the longer time periods required to develop geothermal plants, alternative assessments of operating cost derived from research documented in the binder library, and a range of capital costs from various sources, including estimates made by developers with projects in the pipeline.

Geothermal energy has been investigated in the Caribbean for decades. However, no projects have yet been developed in CARICOM countries. Various references in Binder 16 document problems with development of geothermal resources in the region. Some of the problems with geothermal plants identified by authors -- with which we do not necessarily agree -- include:

- No economic incentives for geothermal development;
- The difficulty in financing small projects (below $50 million or 20MW);
- The speckled history of fiscal responsibility on the part of the governments of several of the islands and their consequent low international credit ratings;
- The relatively poor financial condition of the national utility companies; and

[20] The Status and Future of Geothermal Electric Power, Binder 16

- The inability or unwillingness of the national governments to guarantee payments by their utilities for power purchases.[21]

Screening Models for Geothermal

Unlike the wind projects, screening models are not much help in the analysis of geothermal projects. This is because of the site specific nature of capital costs for geothermal facilities. As noted by the World Bank Group, "the economics of geothermal extraction are highly variable and wide ranging" (Binder 16). A World Bank study estimates the cost per KWh to range between 2.5 cents per KWh and 10.5 cents per KWh depending on resource quality and the size of the plant. However, one factor that does not vary in the various analyses is the capacity factor of the plant which is generally estimated to be 90% or above. There are seven geothermal plants in the pipeline with a total capacity of 59 MW.

The modelling by CARICOM assumed a capital cost of $4,000/KW and an operating cost of 2 cents per KWh. The previous modelling did not distinguish between development costs and plant costs, it did not reflect the timing of construction expenditures, and it did not consider different tax and financing possibilities that may be available for geothermal plants. The remainder of this section describes resource assessment for geothermal plants, the capital cost of geothermal plants, the operating cost of geothermal plants, and the project finance modelling of geothermal plants.

Geothermal Resource Assessment

Geothermal resources have been actively discussed for CARICOM countries for the past twenty years. According to Gerald Huttrer, "The potential for construction of small to medium sized (5-25 MW) geothermal power generation facilities is excellent in many countries. Geothermal indicia including warm to hot springs, fumaroles, solfataras and mud pots exist, to varying extents, on St. Kitts, Nevis, Montserrat, Dominica, St. Lucia, St. Vincent, and Grenada… Prior to 1995, geothermally oriented geologic, geochemical and geophysical studies were conducted on Dominica, Montserrat, St. Lucia, and Grenada. Ten 500 meter deep wells were drilled at Watten Waven in Dominica and two deep exploration wells were drilled in St. Lucia in 1984-1987"[22].

Geothermal Capital Cost

The key variable that affects geothermal plants is the capital cost per KW rather than the capacity factor (the capacity factor ranges between 90% and 95%, depending on the availability of the equipment). The accompanying graph illustrates capital cost/KW from the screening analysis and from the pipeline.

[21] Geothermal Resources in Latin America & the Caribbean, Binder 16

[22] Geothermal Activity Status in the Volcanic Caribbean Islands, Gerald W. Huttrer (Binder 16)

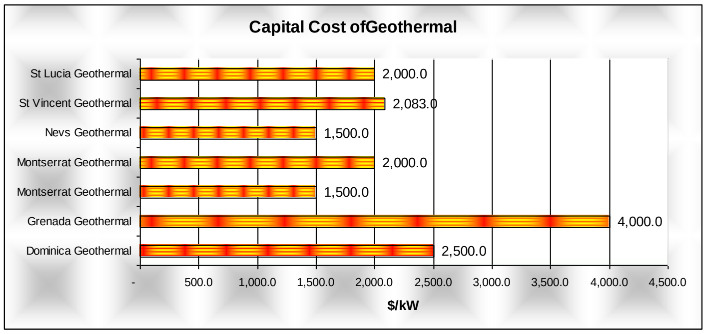


Figure 28 - Capital Cost of Geothermal

Given the wide range in cost estimates, we have investigated other sources of cost data. Various sources documented in Binder 16 describe how geothermal expenditures should be split into three categories as follows:

1. Geological Investigations
2. Exploration of wells and Capacity Tests
3. Drilling of Wells and Plant Construction

In the discussion below, we evaluate the timing of expenditures and the amounts of expenditures associated with these three stages.

Geological Investigations (Exploration)

According to Claude Bannwarth of EDF (Electricite de France) who has developed a geothermal plant in Guadeloupe, the first step (identifying sites and pre-feasibility) should take 3 to 6 months and cost $150,000 - $400,000[23]. For a 5MW plant, this represents $30-80/KW. The World Bank study uses a significant cost estimate ranging between $400/KW and $1,000/KW as follows for various types of plants:

Table 21 – Stage 1 Cost ($/KW)

	$/KW		
	High Quality Resource	Medium Quality Resource	Low Quality Resource
Small	400-800	400-1000	400-1000
Medium	250-400	250-600	-
Large	100-200	100-400	-

The geothermal resources in the CARICOM countries are generally high quality. A report titled "Geothermal Resources in Latin America and the Caribbean" included in binder 16 documents the exploration already completed in the region. The report notes "in the cases of Dominica and St. Lucia, intense surface hydrothermal activity marks the

[23] Bouillante Geothermal Plant, Guadeloupe, Claude Bannwarth (Binder 16)

presence of high enthalpy geothermal systems, 230°C at Watten Waven in Dominica and 300° C in St. Lucia"[24].

In St. Lucia, a field study was done in 1971 and pre-feasibility studies were completed in 1988. However, the projects have been stalled due to problems with concrete results from exploration. According to Huttrer, the well in St. Lucia has "suffered mechanical failures and the produced steam was never harnessed to generate power. There has been no deep drilling in the Caribbean since the completion of this well in 1988".[25]

Exploration and Capacity Testing

As described by EDF, the second step – exploration of wells and capacity testing -- involves drilling of small diameter wells and testing of the reservoirs. This step is expected to take 6 to 12 months, and to cost "$2.5 million to $4 million depending on depth, access, local companies, etc". For a 5MW plant, this amounts to approximately $500-800/KW. According to Charles F. Kutscher, exploration costs are $700/KW for steam plants and $500/KW for binary plants[26]. The World Bank report states that costs for the second stage are as follows depending on the resource quality and the size of the project:

Table 22 – Stage 2 Cost ($/KW)

	$/KW		
	High Quality Resource	Medium Quality Resource	Low Quality Resource
Small	100-200	300-600	500-900
Medium	200-500	400-700	-
Large	300-500	400-700	-

Drilling of Wells and Construction of Power Plants

The final stage in building a plant is estimated to take from 24 to 30 months and to cost $25 million to $30 million for a 10MW plant[27]. On a per KW basis, this amounts to $2,500-3,000/KW. According to Kutscher, the plant and equipment costs are $700-800/KW for a steam plant and $1,600/KW for a binary plant. The only developed plant in the Caribbean is a 4.5 MW double-flash power plant in Guadaloupe, commissioned in 1984 and recently expanded. We have interviewed the developer of geothermal facilities in the Philippines. The developer confirmed that final stage costs in the $1,000/KW range are reasonable. The developer also confirmed that project financing can be obtained for IPP thermal plants.

The World Bank cost estimates for the final stage are shown in the accompanying table:

---

[24] Geothermal Resources in Latin America & the Caribbean (Binder 16). Temperatures of 130°C and above can result in power production

[25] Geothermal Activity Status in the Volcanic Caribbean Islands, Binder 16

[26] The Status and Future of Geothermal Electric Power, Binder 16

[27] Bouillante Geothermal Plant, Guadeloupe, Claude Bannwarth (Binder 16)

Table 23 - Stage 3 Cost ($/KW)

$/KW			
	High Quality Resource (>250°C)	Medium Quality Resource	Low Quality Resource (< 150° C)
Small (< 5MW)	1100-1300	1100-1400	1100-1900
Medium (5-30MW)	850-1200	950-1200	-
Large (> 30MW)	750-1100	850-1100	-

Total Costs

This section summarises the total capital costs of geothermal plants and compares the plant costs to cost estimates in the pipeline.

According the World Bank, indirect percent of costs are 5-10% in a developed country, 10-30% in remote developed countries, and 30-60% in developing countries. According to an article included in the Binder Library, current installed costs range from $1,400/KW to $2,100/KW as follows:

- Exploration and Drilling -- $700/KW
- Plant and Equipment -- $700-800/KW
- Total Steam -- $1400 --1500/KW

For binary plants, the cost estimates are:

- Exploration and Drilling -- $500/KW
- Plant and Equipment -- $1600/KW
- Total -- $2100/KW

Other Geothermal Cost Items

Other than the capital costs, the inputs required are O&M costs, capacity factor, plant life and financing assumptions. The capacity factor is often quoted as 90%, and that is the assumption we use for the project models (in the avoided cost analysis, we assume a forced outage rate of 8% and zero fuel costs).

Huttrer estimates the O&M costs to be $100/KW/year, although he notes that “these costs are for plants of 5MW or larger. For small plants under 5MW in size, the cost per KW goes up significantly because of a loss in equipment economies of scale and because of the fixed costs associated with exploring a site and drilling wells are divided by a smaller number of kilowatts. At a 90% capacity factor, the O&M cost equates to $12.7/MWH (1.27 cents/KWH). This implies that estimates used in the pipeline analysis of $20/MWH are probably somewhat high.

Financial Evaluation of Geothermal Projects

In running the project finance model we reflect the judgement that debt financing of exploration costs is virtually impossible. Since geothermal is not a conventional technology, even debt financing of the power plant cost itself will probably be difficult. Therefore, we assume the following financing structure:

Table 24 - Financing Structure

Debt Financing	
Stage 1&2	0%
Stage 3	60%

Chapter IV – Avoided Cost and Resource Assessment

Introduction

The work plan states that the consultant will complete an avoided cost analysis for CARICOM countries:

> "A simulation model will be used to project system average and marginal costs on an hourly basis for 20 years into the future. The projections will necessitate assumptions involving demand growth, fuel prices, hydro availability, maintenance outages, capacity expansion, capacity retirement, and cost of new capacity. The model will project avoided energy costs by rating period and avoided capacity costs according to the cost structure of new plants."

This chapter describes the method we have developed for modelling electricity system costs of Caribbean utility systems and for making detailed projections of avoided costs. In describing the modelling process of utility systems, we discuss measures for three of the four avoided cost components applicable to on-grid renewable technologies – (1) avoided fuel cost; (2) avoided variable O&M cost; and (3) avoided capacity cost. (In this part of the analysis, we do not model the avoided losses that are important in evaluating off-grid projects.)

Through forecasting hourly avoided cost in cases with and without renewable technologies, the modelling techniques described in this chapter can be used to evaluate the economic viability of renewable resources in a detailed and comprehensive manner. As stated in the work plan and the proposal, we are providing software and databases used to compute hourly avoided costs to CARICOM. We hope that utility companies and developers alike will use the modelling process described below to measure the value of renewable technologies in using alternative assumptions with respect to oil prices, load growth, demand patterns and other factors.

The avoided cost analysis can be a powerful tool in supporting financing proposals of renewable projects and be included as an important component of the offering memoranda where a project finance business model is applied. As we explained elsewhere, the most important consideration for investors and lenders in obtaining debt and equity financing is demonstrating that the renewable project is economically viable. The avoided cost analysis using detailed hourly costs described below is the most comprehensive way to measure the economic benefits of a project. More specifically, if PPA prices in a contract exceed the economic benefits to a utility of reduced fuel, variable O&M and capital expenditures for new construction, utility companies will have an incentive to re-negotiate the PPA and not work on a cooperative basis with the developer over the life of the project. On the other hand, if the economic benefits exceed

the PPA costs, the utility company can be expected to work in a positive manner with the developer over the life of the project. Because the economics of the project relative to PPA prices are so important, inclusion of the avoided cost analysis as part of the offering memorandum can significantly improve the presentation.

This chapter explains the avoided cost analysis and the model we have developed for CARICOM and walks through the model using a case study of Grenada. The chapter is designed to explain practical elements of the software and the analytical approach so that utility companies, developers and government agencies can perform the analysis independently in the future. In explaining the analysis, we have separated the discussion into the following sections:

1. Introduction and Summary Results
2. Objectives of Avoided Cost Modelling
3. Avoided Cost Assumptions and Results in the Status Quo Case
4. Economic Viability of Geothermal Resources
5. Modelling of Wind Energy Resources
6. Economic Viability of Wind Resources
7. Modelling of Capacity Credits and Loss of Load Probability
8. Sensitivity Analysis of Wind Resources

The Utility Survey

The avoided cost analysis presented in this chapter requires detailed data on the amount of electricity demand (hourly loads) and the characteristics of current generating plants that are used to produce electricity (plant by plant operating data). As explained in Chapter 1, we have developed a survey that requests necessary data to complete the model of avoided cost on a system by system basis. The current status of responses to the survey is summarized on the following table:

Table 25 - Status of Survey Responses

Country	Utility	Utility Survey Received	Last Contact
Antigua and Barbuda	Antigua Public Utilities Authority	Yes	
The Bahamas	Bahamas Electricity Corporation (BEC)	Yes	
Barbados	BL&P	No	Will not be completing survey
Belize	Belize Electricity Ltd (BEL)	Yes	
British Virgin Islands	B.V.I. Electricity Corp.	Yes	
Dominica	Domlec	Yes	
Grenada	Grenlec	Yes	
Guyana	Guyana Power & Light	No	They are filling out the survey.. It will take them a while because they don't have the information on hand.
Jamaica	JPSCo	No	
Montserrat	Montserrat Electricity Services	Yes	
St. Kitts and Nevis	Nevlec	No	
St. Lucia	Lucelec	No	He spoke with Carilec. Some of the utility managers are a bit concerned about some of the information required. They are trying to figure out how to proceed with this matter. He will have something for us by the end of the week.
St. Vincent & the Grenadines	Vinlec	No	
Suriname		No	
Trinidad & Tobago	PowerGen	Yes	Said that most of the information could come from their sister company T&TEC. The person who is filling it out hasn't completed it yet, but will send a detailed e-mail to us tomorrow with explanation. Right now, they have some plant info from their company for us, but he said they could get info for other things from T&TEC.
Turks and Caicos Islands	Turks & Caicos Utilities Ltd.	No	Secretary gave him message and his response is that he has gotten the questionnaire and will complete next Monday and send to us

Five of the utility companies have provided both hourly load and plant data necessary for operating the model. Nora Hussar and Cicely Cramer have made numerous follow-up contacts with utilities, and we expect to receive most of the surveys. The survey results are included in Binder 27.

This chapter focuses on comprehensive presentation of the analytical approach using a single case study. The case study demonstrates how to develop plant, hourly load and parameter databases in the avoided cost model, and how to use different modelling approaches to determine the economic viability of alternative renewable technologies. By working through a complete case with different types of renewable resources for a utility system in the Caribbean region, issues associated with the mechanics of the modelling process that will apply to other systems can be addressed. We have completed the databases for other systems that have provided data, which are included in Volume II. These systems include Dominica, the Bahamas, British Virgin Islands, and Antigua. The utility companies in Barbados and Belize stated that they would not provide the data.

Avoided Cost Modelling and Transparent Economic Analysis

While we have not received data to complete an avoided cost analysis for each utility system in the CARICOM region, we have developed a process that is tailored for utility companies in the region as well as for renewable wind, geothermal and biomass resources that are deployable in the Caribbean. Working through the Grenada case study from data entry to computation of sensitivity analysis illustrates the process that we have developed.

We hope that distribution of this report and explanation of the detailed case study of Grenada will prompt other utility companies in the region to submit and/or refine the hourly load, plant, and fuel cost data requested by CARICOM.

By illustrating the hourly avoided cost approach from A to Z for a single system, stakeholders should realise that our goal is to provide rigorous and objective analysis of renewable technologies and not to bias the analysis in favour of renewable projects. Given the need for renewable subsidies in other geographic and economic environments (such as production tax credits in the US and subsidies in Germany), CARICOM utility companies may reasonably be concerned that the renewable technologies cannot work on a standalone basis without government help. On the other hand, if utilities question the benefits of renewable projects, they may be accused of being environmentally stubborn. Using the modelling process described below, the utility companies and developers can construct the analysis using an open and comprehensive process. Through attending a workshop, the utility companies can have direct input into the process. The avoided cost analysis provides transparent information on the economic benefits and costs of renewable resources. It is transparent because the model is available to both utility companies and developers and because all of the modelling techniques are clearly described and fully documented.

Summary of Grenada Results

The detailed analysis of the Grenada system described below proves the economic viability of wind and geothermal projects for the island. The analysis demonstrates that a system where geothermal plants meet base load requirements and wind power provides additional energy shows that Grenada put itself in a unique position in terms of environmental commitment. Importantly, an environmental strategy also provides very significant electricity bill savings to people on the island.

The analysis in this chapter also provides a detailed computation of avoided cost. The modelling demonstrates that avoided costs are above average fuel costs estimated from either fuel cost surcharges or from average fuel costs computed using annual report data.

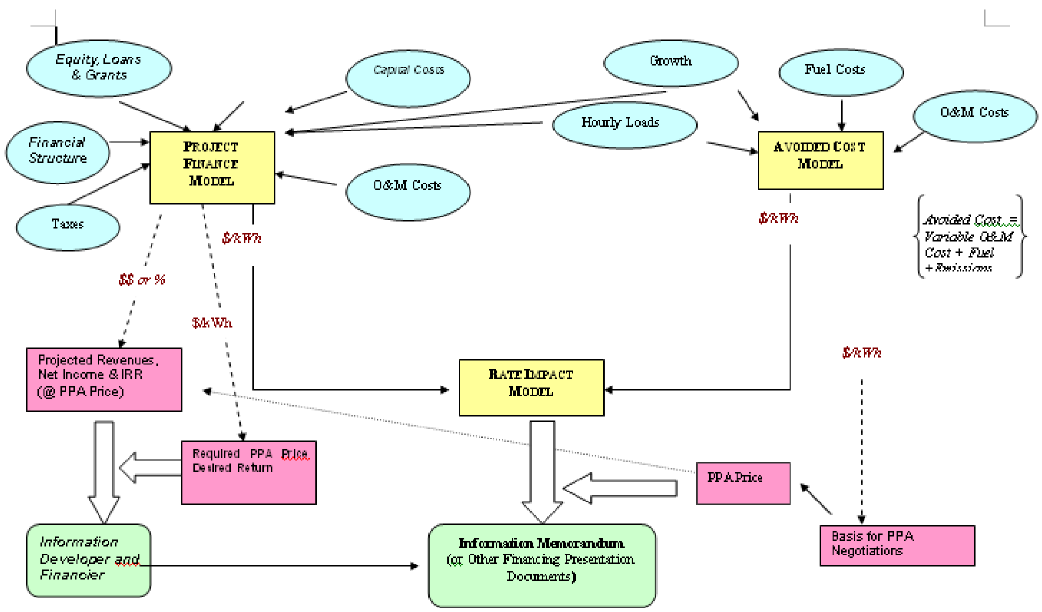
The case study of Grenada shows that a 12MW geothermal project and a 3MW wind project in the CARICOM pipeline have significant economic benefits to the country. Over the 25 year analysis in the model, the geothermal project saves more than $45 million on a present value basis. To illustrate the magnitude of the savings, we consider the third year of operation for the plant. The geothermal plant saves $8.3 million in fuel costs and variable O&M costs and $1.1 million in capacity costs in the third year. Offsetting these savings in energy costs are PPA costs that reflect the capital cost and the fixed operating and maintenance costs of the project, at $6.1 million, which are derived from the project finance modelling analysis. Including reliability benefits, the net savings from the geothermal project range from $3.5 million to $4.1 million per year. These savings are very significant relative to total system costs in Grenada. In percentage terms, the net savings range from 16.5% to 25%.

The 3MW wind project in the CARICOM pipeline also results in very large savings relative to the size of the project. Using a similar approach where savings in fuel costs, variable O&M costs and the costs of un-served energy is compared to the PPA costs that cover financing costs and fixed O&M expenses of the project, the annual net savings range from $1,200,000 to $1,700,000 per year. These savings depend to a significant degree on the wind resource assessment. If the wind resources correspond to the greater capacity factors experienced in Curosel as discussed in Chapter 3, the savings increase to $2,000,000 per year. These savings contrast with a PPA cost of $645,000, resulting in annual savings of between $680,000 and $1,000,000 per year. Given that the total cost of the wind turbine is about $3.6 million, the economic benefits are obvious.

Section 1: Objectives of Hourly Avoided Cost Analysis

The modelling analysis described in this chapter measures the economic benefits or costs associated with renewable energy technology projects in a comprehensive manner and it includes a detailed projection of avoided cost. In cases where avoided costs are not measured because data is not available, the rate impact analysis discussed in Chapter 5 is used. The rate impact analysis uses average fuel and variable cost per MWH to measure the cost impacts of renewable resources.

The way in which the avoided cost model is used together with other parts of our analysis as illustrated in the diagram below (repeated from Chapter 3). The avoided cost model provides inputs on the avoided costs, the capacity credits, and the net generation of alternative types of units that is central to determining economic viability. This data is combined with required project cost from the project finance modelling to evaluate the net economic viability of the renewable project.



As explained in Chapter 3, the fact that PPA prices are used to represent fixed costs of the renewable projects does not mean that a project finance model is necessarily assumed as a business model. If the projects were built by Grenelec rather than an independent developer, the company would have to finance construction costs of the project and incur operation and maintenance expenses. These costs are reflected in the minimum PPA price.

Binder Library Resources for Avoided Cost Modelling

As with other portions of the project, the avoided cost analysis makes use of data and modelling approaches that are documented in the "CARICOM Binder Library". Information used as background in the avoided cost modelling analysis include Binders 20, 21, and 22 on Wind Case Studies; Binders 13 and 14 on Fuel Price Forecasts; Binder 26 on Utility Survey Responses and Binder 19 on Wind Supplier Information. The contents of the binders are available to stakeholders on compact disks.

Section 2: Avoided Cost Measurement in the Status Quo Case

The model described in this chapter measures utility system costs on an hourly basis. The model computes avoided cost in each hour by measuring the fuel cost, the variable O&M cost, and emission reduction value of the last plant to dispatch on a system in an hour. The hourly avoided cost is aggregated for the month and the monthly analysis is aggregated for each year. The hourly analysis is performed for up to 25 years and includes assumptions regarding load growth, capacity expansion, fuel costs, variable O&M costs, costs of un-served energy, outage rate analysis, heat rates, CO_2 emissions, and other items such as the capital cost of new diesel plants.

The impacts of various assumptions and modelling techniques on annual average avoided cost in 2005 are shown on the accompanying table. In this section we only discuss results in the status quo case that does not include renewable resources. We label the case with no renewable resources the status quo case rather than the baseline case in order to differentiate between different fuel price and other scenarios that can vary across cases. For example, the status quo case involves three different fuel price scenarios – the status quo/reference oil price, the status quo/high oil price, and the status quo/low oil price case.

26 - 2005 Avoided/Average Cost

	2005 Avoided Cost	2005 Average Cost
Base Case	$101.63/MWH	$75.65/MWH
Monte Carlo Simulation on Outage	$122.89/MWH	$74.85/MWH
High Oil Price Case	$119.59/MWH	$93.23/MWH
Low Reserve Margin	$105.05/MWH	$74.04/MWH

Avoided cost measures that amount by which a renewable technology can reduce the fuel and variable costs while the average costs measures the total fuel and variable O&M costs of the system divided by the total amount of generation for the year. The reason avoided

cost is greater than average cost is due to the shape of the supply curve as explained below. Average costs can be calibrated to the utility annual reports, while there is no easy way to benchmark avoided cost if no studies have been performed by the utility company.

The avoided cost results come from assumptions with respect to loads, existing power plants, new power plants, and renewable resources. Assumptions for the most important variables are discussed in the remainder of this section of the chapter. Our discussion covers the following assumptions:

- Hourly Loads
- Load Growth and Capacity Expansion
- Scheduled and Forced Outage Assumptions
- Oil Price Projections
- Variable O&M Cost per MWH
- Heat Rate Assumptions
- Outage Rate Mechanics
- New Capacity Characteristics
- Emission Rates and Emission Costs

Hourly Loads

One of the reasons for modelling hourly avoided costs rather than annual data is that the cost that is avoided by a renewable resource can be quite different in different hours of the year. The differences in hourly avoided cost are driven by the fact that electricity cannot be stored, that loads vary by time of use, and by the fact that there is an upward sloping supply curve driven by cost variation of plants on a system. In the case of Grenada, the hourly loads have patterns for a winter month (January or month 1) and for a summer month (July or month 7) that are shown on the graphs below. The data demonstrate that there is little variation from week to week while the difference between daytime and night time loads is significant. The hourly load patterns are important in evaluating the economic benefits of renewable technologies. In the case of geothermal plants, since the plants are base load, the amount on geothermal plants should not exceed the minimum load (about 10 MW). In the case of wind, the model simulates each hour of operation of a wind turbine relative to the amount of wind production.

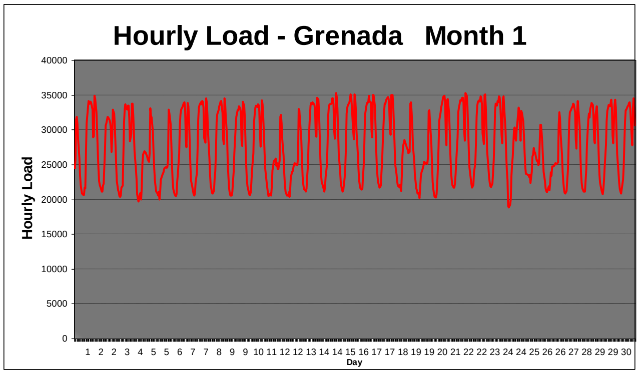


Figure 29 - Grenada Hourly Load Month 1

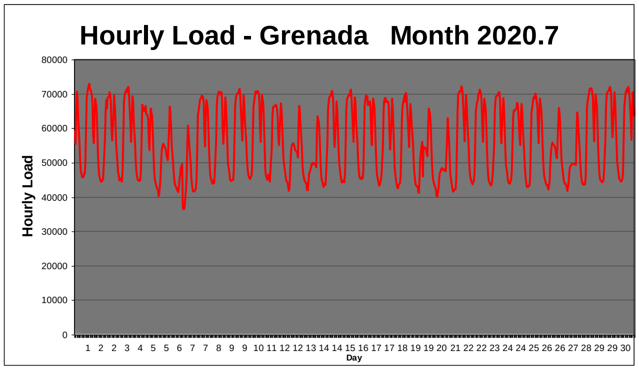


Figure 30 - Grenada Hourly Load Month 2020 - 7

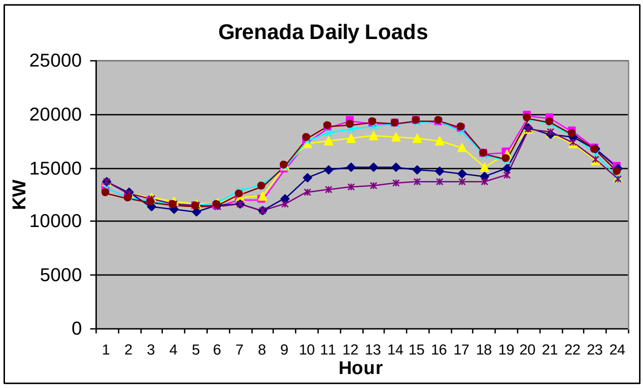


Figure 31 - Grenada Daily Loads

The hourly loads are extended into the future by assuming monthly load growth and the monthly pattern remains the same. For example, loads in the year 2020 have the same hourly pattern over a month as the graphs for 2003, but are all scaled by the increasing proportions due to the growth in load. The monthly load graph below shows that as in the case of weekly load variation, there is relatively little variation from month to month. This suggests that there is no particular month which is advantageous.

Load Growth and Capacity Expansion

In building capacity to meet future load growth, alternative analytical approaches can be used to determine the timing and amount of new capacity. The model provided as part of this consulting project includes alternate methods. For example, the model can automatically build capacity based on the required reserve margin, or it can build capacity through evaluating the net value of new plants that considers the cost of un-served energy and the fixed cost of new plants. For Grenada, we assumed a reserve margin of 40% requirement for building new capacity. This criteria roughly corresponds to the N-2 rule used by the company. (The N-2 rule states that a sufficient amount of capacity should exist on the system such that demand can be met with the two largest sets down with de-ration or retirement of older sets is factored in.)

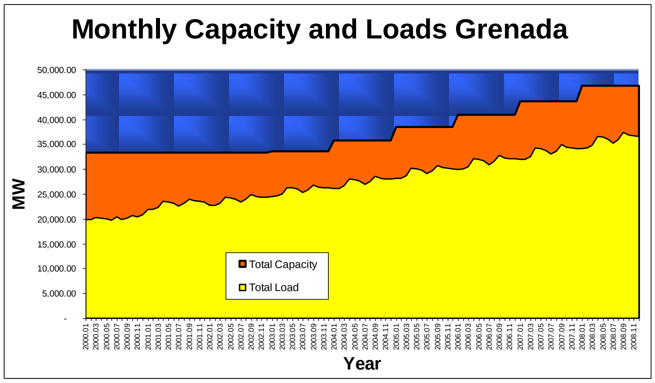


Figure 32 - Grenada Monthly Capacity and Loads

The monthly and annual capacity relative to load is illustrated in the accompanying graphs. Note that the model builds a significant amount of new capacity to meet the growth in load and retirement of existing capacity. New capacity assumptions can have significant effects on avoided cost because depending on the characteristics of new capacity and the amount of new capacity added, the avoided costs can change significantly. To demonstrate the effect of reserve margin and new plant characteristics, the accompanying table shows the effect of different reserve margin and capacity mix assumptions. With a lower reserve margin, avoided costs are greater because the peaking capacity is operated more often. In cases where more medium or slow speed diesel is added as compared to high speed capacity, the avoided costs are lower because the running costs of base load plants are lower than the running costs of the base load plants.

Table 27 - 2005 Avoided/Average Cost

	2005 Avoided Cost	2005 Average Cost
40% reserve margin	$101.63/MWH	$75.65/MWH
25% reserve margin	$105.05/MWH	$75.74/MWH
100% slow speed; 40% Reserve Mgn	$98.96/MWH	$75.62/MWH
100% high speed; 40% Reserve Mgn	$110.07/MWH	$76.04/MWH

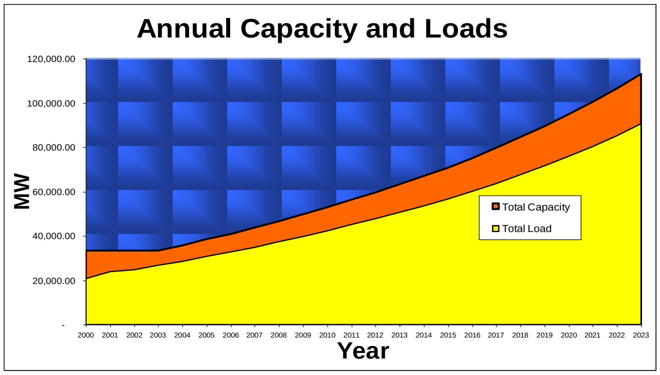


Figure 33 - Annual Capacity and Loads

Scheduled and Forced Outage Rates

Once the loads are entered, a database of existing production plants is developed for each utility system scheduled. The plant data includes retirement of capacity, forced outage assumption, maintenance outages, heat rates, fuel prices, variable O&M costs, and emission rates. In this section we discuss the assumptions with respect to plant availability and forced outage – the percentage of the time that units are out for maintenance that is not scheduled ahead of time. The graph below shows a distribution of plant availability data that was supplied by various companies in response to our survey, and illustrates that 10 of the plants surveyed had an availability of 88%.

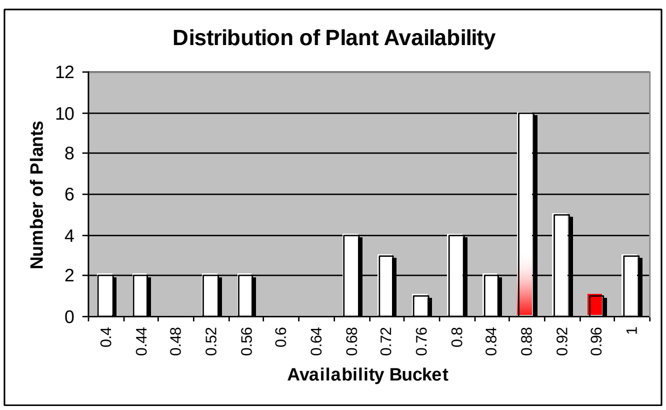


Figure 34 – Distribution of Plant Availability

The forced outage rate of plants is an important variable in establishing the relative capacity benefits of different types of units. If outage rates for diesel units are very high, then the reliability or capacity value of renewable technologies is greater on a relative basis. Say the diesel units have forced outage rates of 30% instead of 15%. The reliability benefits of wind capacity and geothermal will then be greater. The graph above shows that for the region, the median availability rate is 82.26%, and the average availability is 74.56%. In the base case, we apply an availability assumption of 82.26% to the diesel units.

To apply the outage rates in the model, two general methods can be applied. The first method simply de-rates the plants in each hour. De-rating of a plant means that the amount that can be dispatched is reduced by one minus the outage rate. The second method applies a Monte Carlo simulation where, depending on random draws, the plants are either fully available or not available at all. (This is a stochastic rather than a deterministic method). The Monte Carlo case generates avoided costs that are higher than avoided costs generated using the de-rate method. The table below illustrates results from alternative cases with respect to outage rate assumptions. The Monte Carlo case is more appropriate from a theoretical perspective, but it requires more computer time. In presenting the results below, we use both cases.

Table 28 - 2005 Avoided/Average Cost

	2005 Avoided Cost/MWH	2005 Average Cost/MWH
Base Case De-Rating (87% availability)	$101.63/MWH	$75.65/MWH
Base Case – Monte Carlo	$122.89/MWH	$74.85/MWH

The availability has to be split between scheduled maintenance and forced outage. Using data from the Bahamas, we assume 18 days of scheduled maintenance and the balance is forced outage. This implies a forced outage rate of 12.81%.

Fuel Costs

Oil price forecasts are the main driver of avoided costs, and reduced oil imports are a key benefit of renewable projects. Fuel costs per MMBTU are not published in annual reports, and only one company – Antigua – provided monthly cost per MMBTU in the survey response. (Traditionally, fuel costs are measured in $/MMBTU, which is translated into $/MWH using heat rates). Grenlec stated that the costs for all of its units on a dollar per BTU basis are the same for each unit on its system (see the utility survey response included in Binder 26). Further, the company stated that the costs of its units are $7.6/MMBTU. Data provided by Antigua suggests that the cost of heavy fuel oil is between 50% and 75% of the cost of diesel fuel. A few of the systems use heavy fuel oil as well as diesel fuel. The Jamaican study using WASP assumes that heavy fuel is 57% of the cost of diesel fuel. We assume that heavy oil is priced at 60% of the cost of diesel fuel in the analysis.

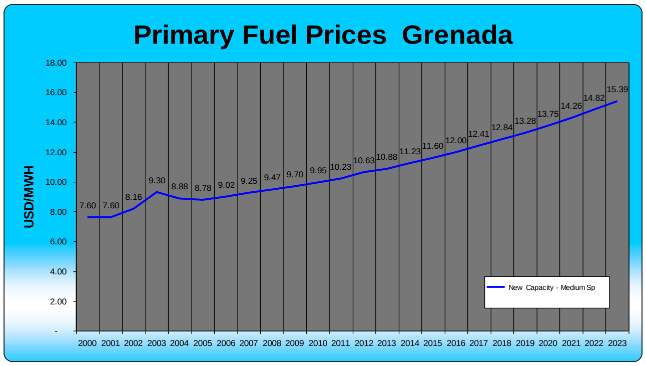


Figure 35 - Grenada Primary Fuel Prices

The fuel costs are escalated using the EIA price forecasts. This is discussed in detail in Chapter 5. The same annual indices are used to escalate plant costs in the avoided cost analysis. Using the EIA data, a base case, high case, and low case fuel price scenario is developed. For the Grenada case study, if the high case fuel price forecast is used, 2005 avoided cost increases from $102/MWH to $123/MWH.

Heat Rates

In modelling avoided costs, various different approaches can be used to represent heat rates – the amount of fuel used relative to the electricity generated. Issues involving heat rate data include what heat rates should be applied to different plants, how the heat rates should change as the plant ages (known as heat rate degradation), and how heat rate curves should be developed. Heat rates on diesel plants provided in response to the survey vary between 8,000 BTU/KWH and 12,000 BTU/KWH. Plants that are older and plants that are smaller generally have higher (worse) heat rates.

The difference in heat rates implies that the cost of running plants differs by quite a wide margin depending on the load. The difference in running cost means the cost of the last unit to dispatch – the avoided cost – can be a lot higher than the average cost of all units on the system. This means that use of average fuel cost per MWH statistics from annual report data or fuel surcharge tariffs can understate avoided cost.

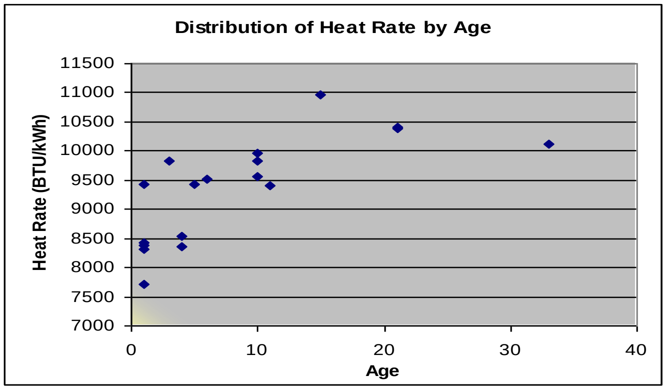


Figure 36

The model has been refined to reflect the decline in avoided cost that accompanies increasing heat rates as plants age. The model also accounts for the partially offsetting effect of adding new plants with lower initial heat rates and later increasing.

For some countries, heat rate data was not supplied. In these cases, we have estimated the heat rate using a regression equation as follows:

Heat Rate = 9,462 + 46 x Plant Age - .128 x Plant Capacity

Avoided Cost During Plant Outages

In some hours, there is not enough capacity to serve the entire load. In these hours, some customers must be interrupted or voltage must be reduced. The avoided cost in these hours is, in theory, the amount it would take to encourage people to reduce load. We assume that the avoided cost in the unserved hours is $150/MWH. This data is consistent with the WASP study in Jamaica.

Variable Operation & Maintenance

Variable operation and maintenance costs can be an important element of avoided costs and are relatively high for diesel plants. The variable cost for diesel plants is discussed in Chapter 5, which includes estimates of costs from the Jamaican IPP plant. While we requested variable cost data from utility companies on variable costs, none have provided the data. In the avoided cost analysis, we assume a cost of $15/MWH for high speed peaking type diesel plants, a cost of $7.5/MWH (.45 cents/KWH) for medium speed, and a cost of $5/MWH for slow speed diesel plants.

Characteristics of New Plant Data

As plants are retired and new capacity is built, avoided cost becomes more and more a function of the characteristics of new plants rather than existing plants. As discussed above, the default new plants are slow speed diesel plants, medium speed diesel plants,

and high speed diesel plants. Parameters for the new plants include the heat rate on the plant, the variable O&M cost for the plant, outage rates, fuel costs, the plant life, and the carrying cost of constructing the new capacity, including fixed O&M expenses.

For most of the inputs related to new plants, the inputs are similar to the default inputs for existing plants. For example, the heat rates, fuel costs, and outage rates have been discussed above. We assume a heat rate of 8,500BTU/KWH for high speed plants; a heat rate of 8,000BTU/KWH for medium speed plants; and a heat rate of 7,700BTU/KWH for slow speed plants. The cost of new diesel plants is assumed to be $800/KW for high speed plants, $1,150/KW for medium speed plants, and $1,600/KW for slow speed plants. Applying these costs and fixed O&M costs through a project finance model results in carrying charges of $141/KW/Year for diesel plants; $218.27/KW/Year for medium speed plants; and $283.53/KW/Year for slow speed plants.

Emission Rates and Emission Value

We have included algorithms to reflect the impact of renewable projects on the amount of CO_2 emissions and the value of the emission reductions. To do this, we apply an emission rate to each plant in the model on a CO_2 tons/GWH basis. These rates depend on the age and the technology of specific plants. We have used studies performed at the University of the West Indies to gather specific plant data. The emission rates are in tons of CO_2 per MWH. These rates vary from 0.77 tons/MWH to 1.77 tons/MWH (in RETScreen). Once the plant by plant emission rates are developed, these rates are multiplied by a value of emissions per ton. This yields a cost per MWH which is added to the variable O&M for each plant. The dollar value of CO_2 emissions are computed at $5/ton and escalated by 2% as in RETScreen. The increase in variable O&M due to emissions is illustrated in the formulas below:

$$\textit{Value of } CO_2\textit{/MWH} = \textit{Price of } CO_2\textit{/ton x } CO_2\textit{ tons/MWH}$$

$$\textit{Variable O\&M/MWH} = \textit{Value without } CO_2 + \textit{Value of } CO_2\textit{/MWH}$$

Avoided Cost Results

This section presents results of the avoided costs using different analytical approaches with respect to forced outage rates. We show annual avoided costs, monthly avoided costs, and hourly avoided costs. Avoided costs are shown for the following two scenarios:

- Base case fuel costs using average heat rates, the de-rating (deterministic) method for modelling outages, and a reserve margin of 40%.

- Same as base case, but Monte Carlo simulation is used to represent outages on a stochastic basis instead of the de-rate method. In this scenario, new plants of a

given size are added since if very small plants are added, the reliability statistics are biased downward.

An annual summary of avoided costs is shown on the table below:

TOTAL SYSTEM - YEAR TO DATE	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Peak Load (MW)	21,970.82	23,948.19	24,827.03	26,804.40	28,562.06	30,759.15	32,736.52	34,933.60	37,350.40	39,767.18
Last Year YTD Peak	-	21,970.82	23,948.19	24,827.03	26,804.40	28,562.06	30,759.15	32,736.52	34,933.60	37,350.40
Percent Change	-	9.00	3.67	7.96	6.56	7.69	6.43	6.71	6.92	6.47
Total Capacity	33,320.00	35,922.29	37,240.54	40,206.60	42,843.09	44,600.77	47,467.95	50,653.72	53,037.56	56,469.39
Reserve Margin	51.66	50.00	50.00	50.00	50.00	45.00	45.00	45.00	42.00	42.00
Total Generation	141,642.73	154,390.66	160,056.33	172,804.17	184,135.56	198,299.88	211,047.70	225,212.00	240,792.67	256,373.39
Total Sales	-	-	-	-	-	-	-	-	-	-
Last Year YTD Gen	-	141,642.73	154,390.66	160,056.33	172,804.17	184,135.56	198,299.88	211,047.70	225,212.00	240,792.67
Percent Change	-	9.00	3.67	7.96	6.56	7.69	6.43	6.71	6.92	6.47
Load Factor	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
Hours	8,759.00	8,759.00	8,759.00	8,759.00	8,759.00	8,759.00	8,759.00	8,759.00	8,759.00	8,759.00
Energy Cost ($000)	8,845,718.00	12,023,033.00	11,898,356.00	11,738,543.00	12,564,112.00	15,238,408.00	16,026,598.00	16,848,094.00	18,970,198.00	20,299,394.00
Sales Value	-	-	-	-	-	-	-	-	-	-
Unserved Energy	444.61	806.70	788.32	453.00	208.36	427.81	267.17	165.61	345.19	183.50
Unserved Energy Cost	49,767.08	125,838.40	94,265.47	69,751.48	11,393.33	27,437.94	42,269.46	22,745.69	66,122.34	8,502.83
Unserved Hours	191.40	316.87	316.67	187.07	97.93	188.67	120.87	76.27	139.40	66.67
Loss of Load Probability	2.19	3.62	3.62	2.14	1.12	2.15	1.38	0.87	1.59	0.76
Avoided Cost - Hour wtd	88.61	105.23	98.27	97.39	99.12	105.38	106.55	108.15	113.72	114.77
Avoided Cost - Load wtd	89.47	106.20	99.50	98.25	99.93	107.00	107.90	109.00	115.40	116.19
On Peak MC - Hour wtd	92.35	109.75	102.16	101.25	103.03	110.73	111.55	112.81	119.67	119.55
Off Peak MC - Hour wtd	85.18	101.11	94.71	93.85	95.55	100.49	101.98	103.90	108.30	110.41
On Peak MC - Load wtd	92.83	110.30	102.59	101.68	103.46	111.35	112.17	113.39	120.47	120.21
Off Peak MC - Load wtd	85.53	101.61	95.20	94.36	96.04	101.11	102.54	104.40	108.89	110.90
Prod Expense ($/MWH)	62.45	77.87	74.34	67.93	68.23	76.85	75.94	74.81	78.78	79.18
Fuel Expense ($/MWH)	62.45	77.87	74.34	67.93	68.23	76.85	75.94	74.81	78.78	79.18

Presentation of the avoided cost results is intended to demonstrate how the model works, provide estimates of the avoided costs on an annual basis, and demonstrate the difference between the Monte Carlo and the de-rate approach. As stated above, the Monte Carlo simulation method is theoretically superior, but it takes much more computer time.

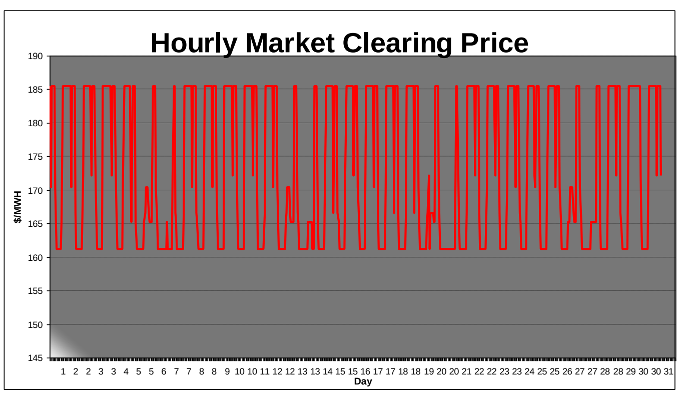


Figure 37 - Hourly Market Clearing Price – De-rate method

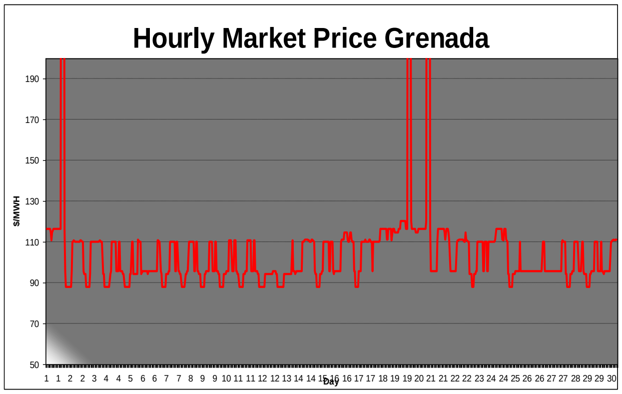


Figure 38 - Grenada Hourly Market Price – Monte Carlo Method

The first graph shows the hourly avoided cost in the simple case with de-rating of plants. The avoided cost follows a similar pattern as the loads and varies between $80/MWH at night and $120/MWH. The graph demonstrates how avoided cost varies with load because more expensive units dispatch at high load times. The second graph demonstrates that avoided cost is stable from month to month and increases with the oil price in future years. The avoided cost estimate of $100/MWH - $120/MWH is significantly above the RETScreen assumption of $73/MWH and is above the average fuel cost/MWH of about $70/MWH discussed in Chapter 5.

The graph below illustrates avoided costs on a monthly basis using the two approaches. Monthly avoided cost range between $100/MWH and $115/MWH. In the Monte Carlo scenario, the costs range between $110/MWH and $130/MWH.

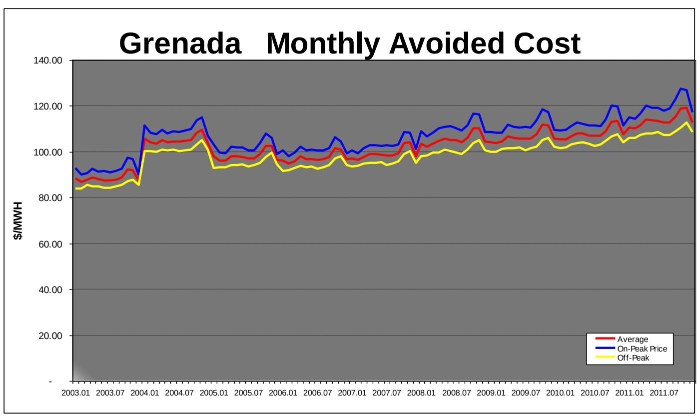


Figure 39 - Grenada Monthly Avoided Cost

The reason avoided costs shown on these graphs are greater than average cost involves the following:

- The cost of the last unit to dispatch has higher cost than the average cost of all units on the system;

- The avoided cost includes variable O&M expense that is difficult to compute from annual report data;
- Avoided cost is affected by hourly load patterns; and
- Avoided cost is affected by the cost of un-served energy

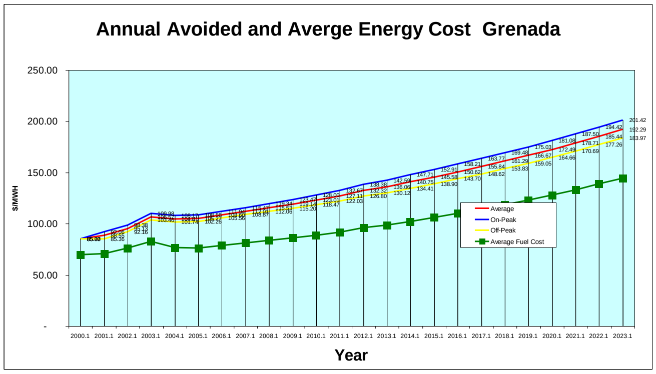


Figure 40 - Grenada Annual Avoided/Average Energy Cost

Monte Carlo simulation is a more realistic way to evaluate reliability because it reflects the fact that plants are either not operational or they are fully operational. The second set of graphs show the hourly avoided costs using the Monte Carlo assumption. In this case, there is more variability in avoided cost and there are price spikes from periods when plants cannot meet the loads.

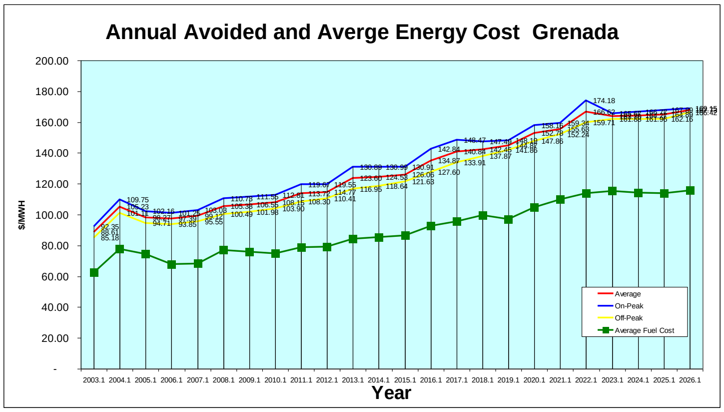


Figure 41 - Grenada Annual Avoided/Average Energy Cost with Monte Carlo Simulation

The graphs of annual avoided cost demonstrates that avoided costs are significantly greater in the Monte Carlo case than in the de-rate case. The graph shows that avoided cost generally follows patterns in oil prices as expected. The long-run avoided costs depend to a significant degree on the assumptions made with respect to new capacity. If the heat rates and variable costs on new capacity are lower, the avoided costs are lower. In addition, variation in the supply curve which drives the difference between avoided

cost and average cost is driven by the decline in heat rates from replacement of less efficient units with more efficient units.

Avoided Costs using Monte Carlo Simulation

Utilities in the Caribbean region have relatively few plants and no interconnections. Because of the small size of the systems, if a few of the plants are out for maintenance, there may be problems in meeting demand. Due to the isolated nature of the systems, modelling of reliability is important.

In the Monte Carlo analysis, the size of new plants has a significant effect on the analysis. Grenlec is intending to add units in 7MW increments. Accordingly, we have applied this assumption.

Loss of Reliability in the Avoided Cost Analysis

The utilities that we surveyed generally have high reserve margins and stringent loss of load probability targets. For example, the LOLP target for Belize is .5%, the LOLP target for BVI is .2%, and the LOLP target in the Jamaica WASP runs was .55%. Further, the utility companies are reluctant to classify wind resources as capacity. Therefore, quantifying the impacts of renewable resources on reliability is an important issue. To measure reliability, we compute the loss of load probability and the un-served energy cost in cases with and without wind resources.

Reliability depends on the number of plants that are out of service. This is why reserve margins tend to be high in the region and it means the outage rate mechanics and the outage rate assumptions are very important in the modelling of reliability. For the case with a reserve margin of 40% and forced outage of 12.3%, the outage hours that result are shown in the accompanying graph. As with all of the analyses in this section, the results are for the status quo case. The outage hours are computed over by averaging the number of hours in a year. The outage hours divided by 8,760 gives the loss of load probability. In subsequent sections we will describe how renewable resources affect system reliability.

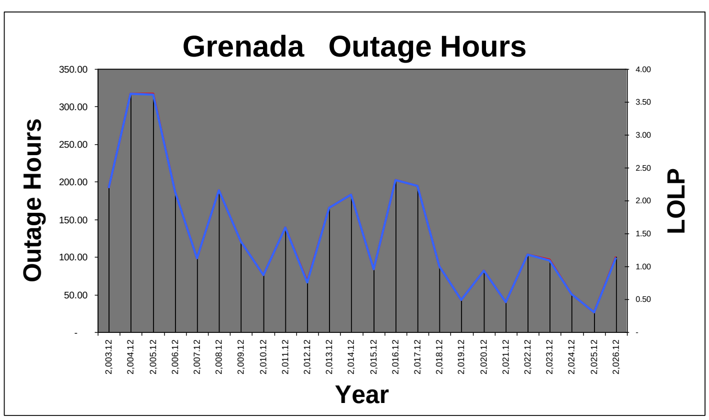


Figure 42 - Grenada Outage Hours

Section 3: Economic Viability of Geothermal Resources

The previous section focused on avoided cost in the status quo case without renewable resources. The remaining discussion in this chapter moves to the cases with renewable resources. We begin by describing geothermal resources, and next we move to wind resources. The cost characteristics and technical aspects of geothermal plants are described in Chapter 3. A conclusion of that section is that the resource evaluation of geothermal plants is relatively straightforward once the wells have been drilled and the resource is established. The capacity factor of geothermal plants is at least 90% once the resource has been established. The key aspect of measuring the economic viability of a project is the capital cost of unsuccessful drilling and questions about the costs of developing pipes and other equipment.

Since geothermal plants do not have boilers and other equipment that diesel plants have which breaks down, and since the flow of steam from below ground is constant, the geothermal plants are expected to have a lower forced outage rate than conventional technologies. This means that if a similar sized geothermal plant and a diesel plant are added to the system, the geothermal plant will improve reliability relative to adding the diesel plant.

To measure the economic viability of geothermal resources, the reduced variable and fixed costs must be measured relative to the increased costs from paying PPA costs. In computing the costs and benefits, a new geothermal plant is added in the model. The geothermal resource can be modelled as a conventional plant with zero fuel cost. Once the plant is input, the dispatch from other capacity is reduced and the amount of new capacity added to the system is also reduced.

The CARICOM pipeline includes a 12 MW geothermal plant to be installed in 2005 in Grenada. This plant is estimated to cost $2,083/kW by the developers and was estimated to have a $4,000/kW cost in the Proform Screening analysis. The plant is estimated to have an operating and maintenance cost of $20/MWH which is substantially higher than cost estimates from our literature search discussed in Chapter 3. Using base case financial, tax, and other assumptions for geothermal plants, the resulting PPA price is $66/MWH as illustrated on the table below. The table shows that the range in required PPA prices for the plant is from $55/MWH to $70/MWH.

ADICA CONSULTING

Table 29 - Grenada Geothermal

Simulate		Case -->	Grenada Geothermal			Capactiy Factor		90.0%		PPA Inflation	2.00%	
						Plant Life		20		O&M Inflation	0.00%	
						Base Plant Cost/kW		2,083.00		Debt Repay	15.00	
	Avoided Cost	Equity IRR	Project IRR	Average DSCR	Minimum DSCR	Plant Life Coverage (PLCR)	Minimum PPA Price	Price vs Base	O&M/Plant	Target IRR	Debt/Capital	Cost per kW w/ Constr Interest
Base	73.00	15.24%	11.09%	2.19	1.79	2.53	$ 63.05		7.57%	15.00%	60.00%	$ 2,453.8
Base	73.00	16.00%	11.5%	2.27	1.86	2.62	$ 62.44		7.57%	15.0%	60.00%	$ 2,453.8
No Development Cost	73.00	16.03%	11.5%	2.26	1.85	2.61	$ 62.37		7.57%	15.0%	60.00%	$ 2,469.0
No Grant on Wind Generator	73.00	16.00%	11.5%	2.27	1.86	2.62	$ 62.44		7.57%	15.0%	60.00%	$ 2,453.8
Higher Capacity Factor	73.00	18.95%	13.2%	2.58	2.09	2.98	$ 55.97		8.83%	15.0%	60.00%	$ 2,453.8
Lower Capacity Factor	73.00	15.16%	11.0%	2.18	1.79	2.52	$ 64.55		7.23%	15.0%	60.00%	$ 2,453.8
High O&M Cost and Inflation	73.00	15.58%	11.0%	2.16	2.02	2.47	$ 63.65		5.68%	15.0%	60.00%	$ 2,453.8
Low O&M Cost and Inflation	73.00	20.44%	14.0%	2.72	2.31	3.14	$ 50.53		2.27%	15.0%	60.00%	$ 2,453.8
High O&M Inflation	73.00	12.75%	9.4%	1.91	1.70	2.17	$ 69.75		7.57%	15.0%	60.00%	$ 2,453.8
10 Year Tax Holiday	73.00	19.20%	14.0%	2.54	2.19	2.92	$ 57.03		7.57%	15.0%	60.00%	$ 2,453.8
25 Year Tax Holiday	73.00	20.13%	14.8%	2.75	2.19	3.19	$ 55.04		7.57%	15.0%	60.00%	$ 2,453.8
Accelerated Tax Depreciation	73.00	16.00%	11.5%	2.27	1.86	2.62	$ 62.44		7.57%	15.0%	60.00%	$ 2,453.8
5 Year Tax Life	73.00	18.05%	12.3%	2.34	2.04	2.73	$ 58.61		7.57%	15.0%	60.00%	$ 2,453.8
High Transmission Cost	73.00	14.91%	10.9%	2.16	1.77	2.49	$ 65.22		7.13%	15.0%	60.00%	$ 2,603.7
Longer Plant Life	73.00	16.67%	12.5%	2.23	1.81	3.11	$ 60.15		7.57%	15.0%	60.00%	$ 2,453.8
3% PPA Inflation	73.00	16.68%	12.0%	2.37	1.86	2.75	$ 60.61		7.57%	15.0%	60.00%	$ 2,453.8
15% Environmental Adder	73.00	19.60%	13.6%	2.65	2.17	3.06	$ 54.30		7.57%	15.0%	60.00%	$ 2,453.8
12% IRR Target	73.00	16.00%	11.5%	2.27	1.86	2.62	$ 55.24		7.57%	12.0%	60.00%	$ 2,453.8
18% IRR Target	73.00	16.00%	11.5%	2.27	1.86	2.62	$ 70.29		7.57%	18.0%	60.00%	$ 2,453.8
75% Financing	73.00	19.15%	11.4%	1.80	1.49	2.07	$ 57.36		7.57%	15.0%	75.00%	$ 2,536.3
60% Financing	73.00	16.00%	11.5%	2.27	1.86	2.62	$ 62.44		7.57%	15.0%	60.00%	$ 2,453.8
9% Interest Rate	73.00	14.88%	11.4%	2.02	1.70	2.29	$ 65.28		7.57%	15.0%	60.00%	$ 2,498.4
8 Year Bond Life	73.00	14.17%	11.5%	1.42	1.22	2.55	$ 67.46		7.57%	15.0%	60.00%	$ 2,453.8
Level Payments	73.00	15.36%	11.5%	2.39	1.48	2.60	$ 64.02		7.57%	15.0%	60.00%	$ 2,453.8
No Debt Service Reserve	73.00	15.64%	11.8%	2.10	1.76	2.38	$ 63.39		7.57%	15.0%	60.00%	$ 2,498.4
Worst Case Financing	73.00	13.08%	11.1%	1.19	0.89	2.01	$ 70.76		7.57%	15.0%	65.00%	$ 2,529.3
High PPA Price	73.00	11.40%	9.8%	1.38	0.97	1.81	$ 75.23		7.13%	15.0%	65.00%	$ 2,683.8
Low PPA Case	73.00	21.64%	16.1%	2.96	2.26	4.03	$ 51.00		7.57%	15.0%	60.00%	$ 2,453.8

To evaluate the economic viability of geothermal renewable technologies using the project model results above combined with the avoided cost model, we use the following four step process:

Step 1: In the first step, we compute total variable costs in status-quo case. In addition to computing the variable costs, we also compute the fixed costs of adding new capacity to the system using the avoided capacity costs discussed above.

Step 2: In the second step we compute the system costs in a second case that modifies the status quo case by adding the 12MW geothermal plant to the system. By adding the geothermal plant, the operating costs (fuel, variable O&M, and emissions) are reduced and the amount of new capacity is lowered.

Step 3: Compute the net savings in system costs of the geothermal renewable resource by subtracting the energy cost and capacity cost in the status quo run made (step 1) from the energy cost and capacity cost in the run with the geothermal plant.

Step 4: Compare the net system cost reductions (computed in step 3) that occur from adding the geothermal plant with the added cost of making additional PPA payments. The difference in the year by year economic benefits of the geothermal plant and the net present value summarizes the net value in a single statistic.

This step-by-step process is illustrated below. Total variable costs (fuel cost and variable O&M for the case with the geothermal plant and the status quo case) are shown on the table below. While the table illustrates results for nine years of data, the actual spreadsheet extends for twenty-five years. The present value of savings shown on the table incorporates the entire twenty-five years of data. In the first part of the table, various cost items are shown for both the status quo case without renewable resources,

and the case with renewable resources. In this case, the geothermal plant variable costs – costs of fuel, variable O&M, and emissions – are lower in the geothermal case than the status quo case because of the reduction in dispatch of diesel plants.

The savings row simply subtracts total cost in the renewable case from the status quo case. The second group of data computes the difference in capacity costs from addition of the renewable project. Since the geothermal plant provides reliable capacity, the amount of capacity (12MW) multiplied by the carrying charges yields the savings. The third category, un-served energy, measures the difference in un-served energy cost between the two scenarios. In cases where a renewable project does not classify as capacity, but does provide some reliability benefits, the difference in un-served energy captures the savings.

The PPA price is derived from the project modelling in Chapter 3 and shown above. This price in $/MWH is multiplied by the renewable energy in MWH to yield the annual cost incurred for the renewable project. The net savings from the project subtracts total cost from the aggregate savings.

Table 30 – Economic Viability of Geothermal Plants

Status Quo Case	3	De-rate case - emissions								
Renewable Case	5	Geothermal - De-rate; Emissions								
PPA Price ($/MWH)	62									
Economic Analysis of Renewable Projects	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Varible Costs (Fuel and Variable O&M)										
Status Quo Case	10,810,109	15,059,632	13,515,502	14,177,762	15,743,183	18,295,702	19,227,086	20,480,645	22,957,418	24,311,858
Renewable Resource Case	10,810,109	15,059,632	5,242,851	6,382,752	7,623,627	9,803,252	10,552,998	11,681,265	14,922,920	15,871,356
Variable Cost Savings	-	-	8,272,650	7,795,010	8,119,557	8,492,449	8,674,088	8,799,380	8,034,498	8,440,502
Capacity Costs										
Status Quo Case	-	-	1,173,149	1,793,640	2,436,724	2,482,003	3,187,174	3,892,378	4,125,273	5,077,252
Renewable Resource Case	-	-	82	30	609,181	620,524	1,274,831	1,946,092	1,650,129	2,538,541
Capacity Cost Savings	-	-	1,173,067	1,793,610	1,827,543	1,861,479	1,912,342	1,946,286	2,475,144	2,538,711
Cost of Un-Served Energy										
Status Quo Case	-	-	-	-	-	-	-	-	-	-
Renewable Resource Case	-	-	-	-	-	-	-	-	-	-
Reliability Savings	-	-	-	-	-	-	-	-	-	-
Total Savings from Renewable Resouces	-	-	9,445,718	9,588,619	9,947,099	10,353,928	10,586,430	10,745,666	10,509,642	10,979,212
Gross Savings Percent	0%	0%	70%	68%	63%	57%	55%	52%	46%	45%
PPA Price/MWH	62.00	62.00	62.00	62.00	63.24	64.50	65.79	67.11	68.45	69.82
Renewable Energy (GWH)	-	-	96,655	96,665	96,671	96,678	96,682	96,686	96,688	96,689
Total Cost of Renewable Resource	-	-	5,992,603	5,993,260	6,113,489	6,236,180	6,361,189	6,488,678	6,618,579	6,750,999
Net Savings	-	-	3,453,114	3,595,359	3,833,611	4,117,749	4,225,242	4,256,988	3,891,063	4,228,214
Net Savings Percent	0%	0%	26%	25%	24%	23%	22%	21%	17%	17%
Discount Rate	7.0%									
Present Value of Savings over 25 years	$46,082,655		PV of Varible Cost Savings		$93,408,733					
			PV of Capacity Cost Savings		$19,607,478					
kW	12,000.00		PV of Reliabiility Savings		$0					
$/kW	2,083.00		Total Savings		$113,016,211					
Total Cost	$ 24,996,000.00									
			PV of PPA Costs		$66,933,556					

The table above shows that the energy cost savings are about $8 million per year and the capacity cost savings are about $1.5 - $2 million per year. These savings compare to PPA costs of $5 to $6 million. On a net basis, the savings represent 26% of the system costs in early years. The analysis confirms that the Caribbean is probably one of the few regions of the world where geothermal is this economic.

Section 4: Economic Evaluation of Wind Resources

In addition to modifying the model to represent unique aspects of Caribbean systems, we have enhanced it to include a number of elements that apply wind resources to utility systems in the Caribbean. For example, the model applies actual hourly data on regional wind speeds to various specific sites for which annual wind speeds have been measured in the region. The model then scales the size specific estimates to the regional hourly data and applies the wind speeds to various wind turbine profiles. This section describes the wind resource modelling of projects in the CARICOM pipeline.

The process we have developed involves converting wind speeds to hour by hour wind electricity production and then evaluating the economic benefits of the resource in the context of hourly avoided cost and hourly loss of load probability. The model incorporates the stochastic nature of wind. This wind resource analysis provides a more detailed measurement of the value of wind energy than is available from screening models such as HOMER and RETScreen because wind resources are measured against hourly avoided costs, because capacity credits can be evaluated, because different site specific wind speeds can be tested, because alternative tax and financial parameters can be measured, because wind variation can be explicitly incorporated in the analysis, because different assumptions with respect to fuel price forecasts can be used and because reliability parameters, such as the value of lost load, can be tested. The analysis is tailored to the region by using Caribbean wind speed data and renewable technologies that work best in the region.

We document the wind resource analysis by addressing the following subjects:

- Development of regional hour by hour wind resource data
- Tabulation of monthly wind speed data for various islands
- Evaluation of site specific wind speed data in different locations
- Construction of hourly capacity factors from wind technology power curves
- Inclusion of wind resources in the hourly avoided cost model
- Measurement of the net economic benefits or costs of wind resources using the avoided cost model
- Sensitivity analysis of the net economic benefits using different wind resource parameters and fuel prices
- Sensitivity analysis using different techniques to represent the stochastic nature of wind speeds

The relationship between wind speed and energy production in the avoided cost model is illustrated on the diagram below:

Average Wind Speed from Data → Distribution of Wind Speed → Power Curve → Hourly Wind Production

The average wind speed and wind distribution is discussed in the first sub-section. This includes discussion of hour by hour wind speed distribution, diurnal wind speed patterns, adjustments for turbine height, island specific wind speeds, and site specific wind speed

adjustments. Next, the power curve for wind turbines and the process of converting the wind data to hourly capacity factors is addressed. Finally, the manner in which capacity factors are converted into economic benefits including the energy costs and capacity credits are described.

While we do not have hourly wind logging data, we did simulate hour by hour wind distribution for the Grenada case study. To do this, we found hourly wind speed data for various general locations in the Caribbean and scaled the hourly data using more detailed site specific data. The site specific data was derived from a study prepared by the Caribbean Meteorological Institute that provided average monthly wind speeds for a variety of locations but did not provide hour by hour data. Our process involves using the hour by hour generic data for the Caribbean to scale the site specific data and then compute hourly capacity factors for different wind turbines. The software we have developed for this exercise demonstrates that depending on the wind turbine, the specific site selected and the method of scaling average wind speed data to hourly data, the capacity factor on a project can vary between 25% and 52%.

Development of Wind Speed Data for Renewable Energy Projects

Resource assessment for wind power is the most complex aspect of measuring the economic benefits of wind power. The capital costs are fairly straightforward and the O&M costs are fairly low. Further, as explained in the chapter on project finance modelling, there is a major issue in the region with respect to the capacity factor that can be achieved for wind farms in the region ranging from 30% to 60%. The wind farms in Curacao have achieved capacity factors of more than 50% that have been considered impossible to achieve.

Since the specific site of a wind farm can have a major effect on the wind speeds, we have created a program that scales regional hourly wind speeds and the wind distribution to specific locations. Various site specific aspects of wind farms are described in the windpower.org website -- see Binder 27. Site specific analysis of wind data includes the following adjustments to the hourly wind speeds discussed above:

- Adjustment to the hourly data for different diurnal patterns
- Adjustments to the hourly data monthly average wind speeds from regional data
- Adjustments to the monthly data for turbine height
- Adjustments to the monthly data for site specific aspects such as hills and roughness of terrain.

Each of these adjustments as well as region wind speed data is discussed below.

Regional Hour by Hour Wind Speed Data

The economic analysis of wind resources requires putting together data on hour by hour wind production. As explained below, we have developed two methods – a stochastic

method and an hour by hour analysis to assess the economic viability of wind farms in the Caribbean. This analysis requires construction of detailed data on how much energy the wind farms produce in each hour. This analysis is more detailed than the RETScreen analysis and from an analytical perspective it provides a tool for use in feasibility studies. Ultimately, site specific data could be entered into this model after hourly data has been collected for specific sites. For example, in response to a survey question, Grenlec stated that it "has undertaken wind data logging on the island of Curacao". This data could provide a more accurate assessment of the economic viability of wind projects.

The RETScreen analysis and European wind studies are based on estimating a Wiebull probability distribution that is skewed to the right as shown above. This distribution evaluates the possibility of different wind speeds occurring over the course of a year. As discussed in the project finance modelling chapter, actual projects must record at least a year of detailed wind data. While the Wiebull distribution may be appropriate for European projects, the distribution of wind speeds in the Caribbean follows more of a normal distribution than a skewed Wiebull distribution.

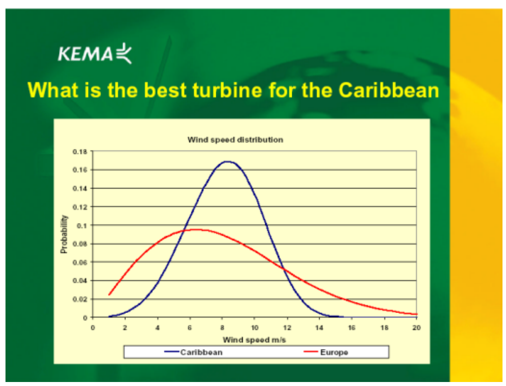


Figure 43 - Best Turbine for the Caribbean

To consider the distribution of wind speeds in the region, we have investigated actual hourly wind speed data rather than attempting to apply a simulated distribution. We have found hourly wind speeds for certain locations in the region. Data has been obtained online from the National Data Buoy Center[28]. The accompanying graphs demonstrate various months of hour by hour wind speeds for the Caribbean in different days. The low wind speed days would generate virtually no power while the wind speeds near 12 m/s imply a capacity factor of near 100%.

[28] Located online at: http://www.ndbc.noaa.gov/Maps/caribbean_hist.shtml

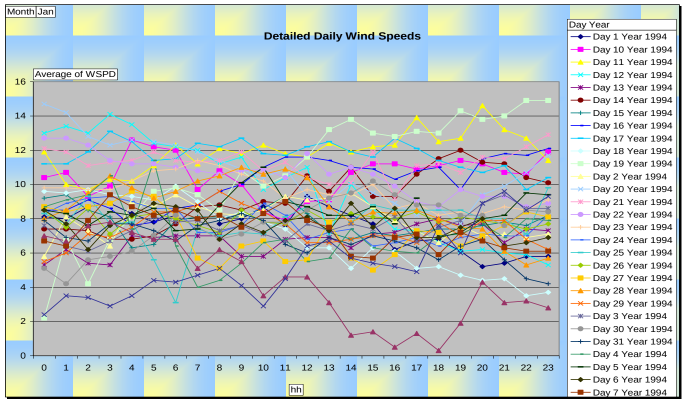


Figure 44 - Daily Wind Speeds

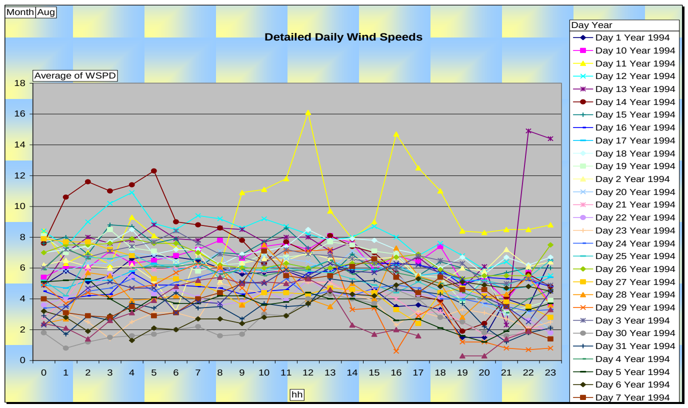


Figure 45 - Daily Wind Speeds

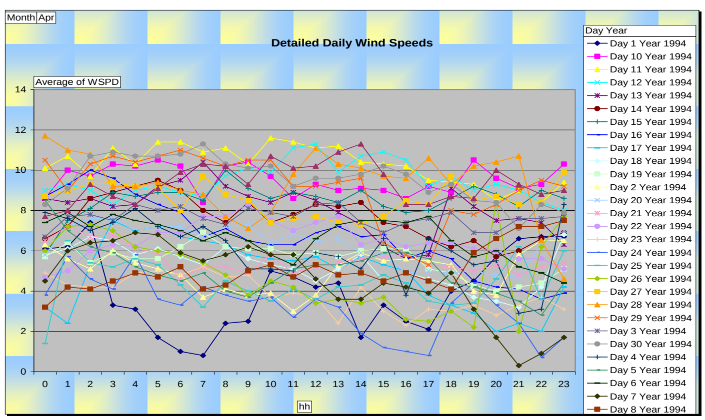


Figure 46 - Daily Wind Speeds

The variability of wind speeds is summarized in the accompanying distribution data. These graphs show that wind speeds do not follow the Wiebull distribution assumed in many areas of the world. Issues in the hourly data include how much does the wind vary on a diurnal basis throughout the day and how much variation in wind speeds occur on a day to day basis. The data seem to suggest that there is not much diurnal variation.

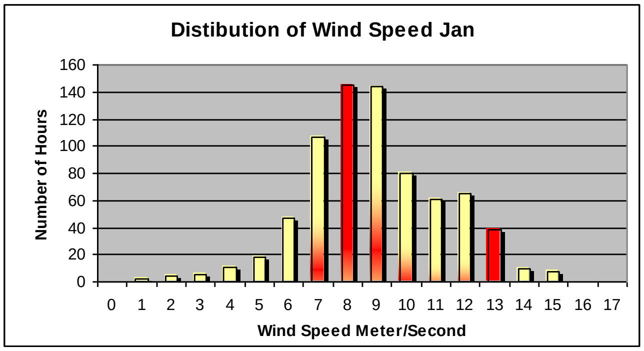


Figure 47 - January Wind Speed Distribution

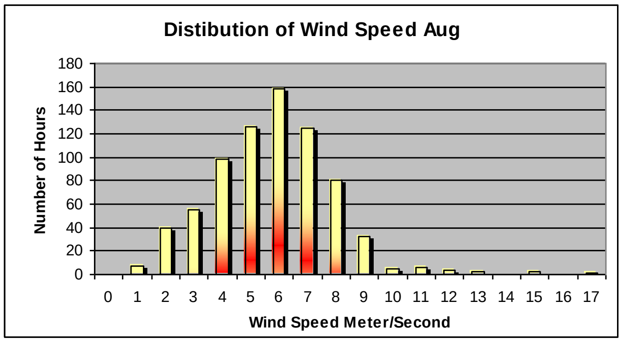


Figure 48 - August Wind Speed Distribution

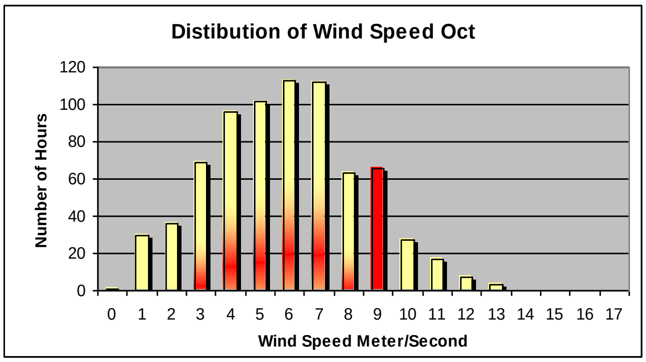


Figure 49 - October Wind Speed Distribution

As projects are developed in the region, hourly site specific data on wind speeds will be available. The software tool we have developed can be used to evaluate technologies and present graphic data for these projects. Issues involving the standard deviation of wind speeds and the shape of wind speed data can then be evaluated in detail.

Diurnal Wind Patterns in the Caribbean

According to windpower.org, in most places around the world it is windier during the daytime than at night. The graph below shows how the wind speed at Beldringe, Denmark varies by 3 hour intervals round the clock.

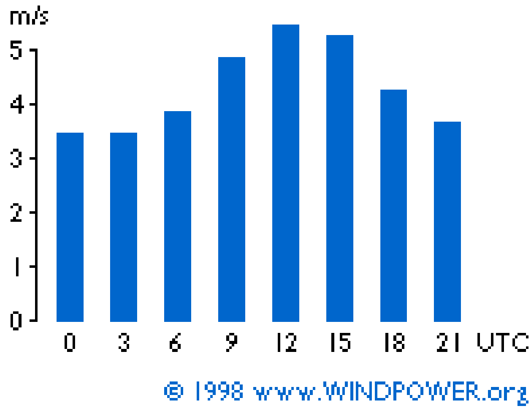


Figure 50 - Wind Patterns

In 1984, The Caribbean Meteorological Institute (CMI) prepared a detailed wind resource and solar assessment that included a number of specific sites in the region. While we do not have hourly data from this study, we do have selected annual wind speed data for various sites and selected monthly data for various islands. In the analysis below we have combined the hourly distribution data with the CMI data and scaled the data to various hours.

Diurnal wind patterns from the Caribbean are illustrated in the graphs below. The diurnal patterns do not show the type of increase in wind speed during the day as the European data. The 1984 CMI study included the following discussion about diurnal patterns in Barbados:

"The Barbados data shows diurnal variation (hourly during day) at the airport shows almost solar insulation type curve rising at sunset from 4.5 m/s. The wind speed rise to 6 m/s around noon and then fall back to 4.5 m/s at sunset. The wind speed is almost constant during the night". The following three graphs compare actual wind speed data with the diurnal pattern suggested in the Barbados analysis.

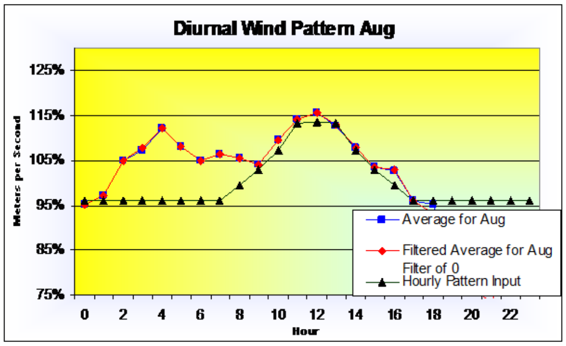


Figure 51 - August Diurnal Wind Pattern

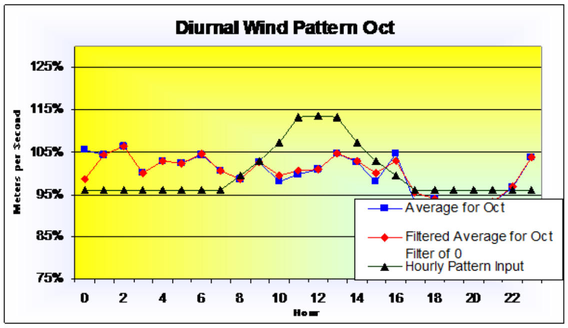


Figure 52 - October Diurnal Wind Pattern

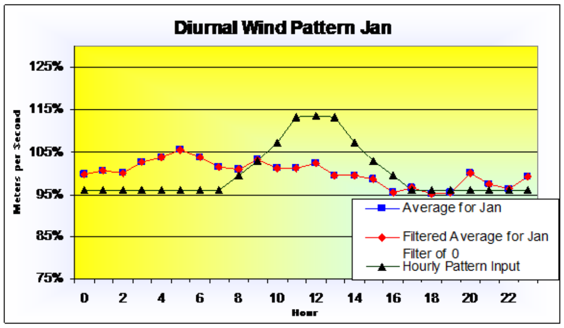


Figure 53 - January Diurnal Wind Pattern

A similar curve exists for the CMI site with the constant 3.8 m/s wind speed during the night slowly rising at sun rise to 6 m/s and then returning to the 3.8 m/s at sun set. The height of the noon wind speed peak is greater for CMI (2.5 m/s as opposed to 1.0 m/s). This suggests that the sites far from the windward cost are more affected by the impact of the hourly variation in solar isolation."[29] The accompanying graphs compare the diurnal patterns of wind speed using the CMI discussion with actual patterns for various months.

We have operationalized the issue of diurnal patterns by developing a model that allows one to use either actual data or the estimated patterns. Adjustments to the diurnal pattern are made by computing the relative daily to monthly ratio and applying the daily ratio to each of the hours in the day.

Adjustments to Wind Speed for Turbine Height

Wind speeds are significantly different at different heights above ground level. (At ground level the wind speed is zero). Typically, weather stations measure wind speed to 10 meters above ground level. The NASA website shows wind speeds both at 10 meters and 50 meters. For Barbados, the wind speed is 16.7% greater at 50 meters than it is at 10 meters. For Dominica, the ratio is 16.9%; for Jamaica and Trinidad, the ratio is 17.0%.

[29] Caribbean Meteorological Institute, 1984

Island Specific Monthly Wind Speeds

Once patterns of wind speeds are established, we have created a model that scales the data according to site specific considerations in the Caribbean. These site specific considerations include the monthly wind speed on the island, the effect of the turbine height, and site specific wind speeds driven by factors related to the terrain. We have developed the model to scale the Caribbean data according to these factors as described below.

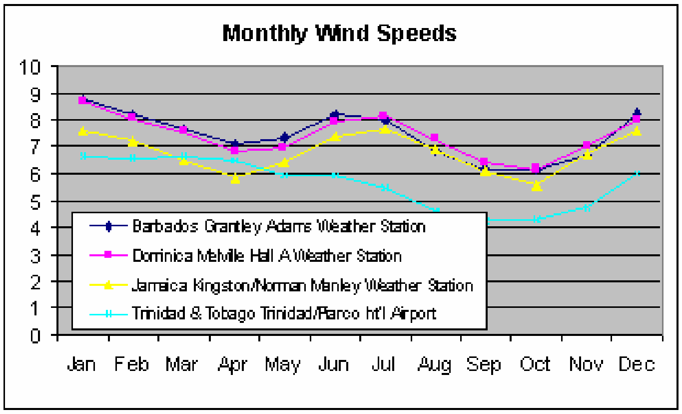


Figure 54 - Monthly Wind Speeds

The monthly wind speeds can also be derived from the NASA web site: http://eosweb.larc.nasa.gov/sse/RETScreen/. Latitude and longitude coordinates of Caribbean weather stations were found using the RETScreen Wind Energy Project Model's Weather Database. An example of the differences in wind speeds from the CMI study for three islands are described below:

Table 31 - CMI Study of Wind Speeds

St. Kitts Wind Resource Assessment	Monthly average wind speeds averaged over a 10-year period vary from a low of 5.0 m/s in November to a high of 6.8 m/s in July. The average wind speed between 1971 and 1980 is 4.8 m/s average. This value varied by under 0.5 m/s during this period
Barbados Wind Resource Assessment	Airport average annual wind data over a 30 year period varied from 4.5 to 6.1 m/s. The related seasonal wind data at the airport gives the highest wind speed in the usual July of 6.4 m/s quickly dropping to 4.8 m/s in September and then gradually rising to the July peak. The NASA average was 6.37 m/s at 10 meters. The wind speed at the southeast coast is 2 m/s higher than the CMI, which is a mile from the west coast. The seasonal variation is very similar but consistently 2 m/s less for every month.
Nevis Wind Resource Assessment	Monthly average wind speeds averaged over a 10-year period vary from a low of 5.0 m/s in November to a high of 6.8 m/s in July. The average wind speed between 1971 and 1980 is 4.8 m/s average. This value varied by under 0.5 m/s during this period.

For the Wigton Wind Farm, wind speeds were measured at 10 and 40 meter heights and the long term speed at 40 meters is estimated to be 8.3 m/s. The range was 4 to 14 m/s[30]. The accompanying graph shows wind speed data for various islands by months at 50m turbine height.

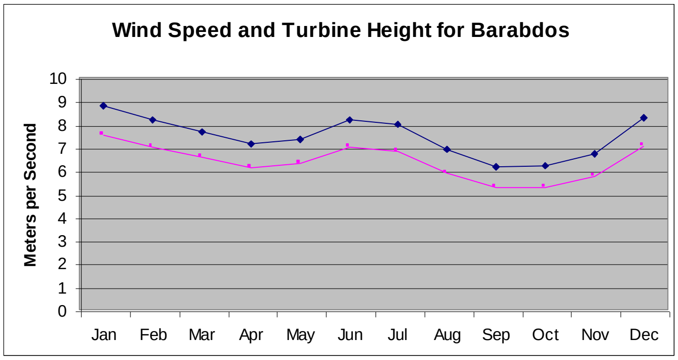


Figure 55 - Barbados Wind Speed & Turbine Height

Site Specific Adjustments to Wind Speed Data

Wind speed data for a region or even for an island can give misleading indications of the resources available for wind energy. Instead, site specific factors can highly influence the wind speed. The following quote from windpower.org demonstrates the importance of site specific factors: "Placing a wind turbine in such a tunnel is one clever way of obtaining higher wind speeds than in the surrounding areas. To obtain a good tunnel effect the tunnel should be "softly" embedded in the landscape. In case the hills are very rough and uneven, there may be lots of turbulence in the area, i.e. the wind will be whirling in a lot of different (and rapidly changing) directions. If there is much turbulence it may negate the wind speed advantage completely, and the changing winds may inflict a lot of useless tear and wear on the wind turbine. A common way of siting wind turbines is to place them on hills or ridges overlooking the surrounding landscape. In particular, it is always an advantage to have as wide a view as possible in the prevailing wind direction in the area. On hills, one may also experience wind speeds that are higher than in the surrounding area. Once again, this is due to the fact that the wind becomes compressed on the windy side of the hill, and once the air reaches the ridge it can expand again as its soars down into the low pressure area on the lee side of the hill".

The CMI study demonstrates how site specific factors related to the location of the wind farms can have an important impact on the wind speeds realized in the Caribbean. The 1984 CMI study illustrates that site specific factors can lead to wind speeds of more than 20% greater than the average speed recorded at the major weather station. For example, in the case of the Wigton wind farm, the wind speed at 40m of 8.3 m/s compares to the airport reading of 6.8 m/s from the NASA website – an increase of 22%.

[30] On the NASA website, the country average was 5.81 m/s and 6.8 m/s. Average wind speeds for Dominica and Barbados were about 9% greater than Jamaica.

CMI performed site specific wind data. Selected examples are shown in the table below:

St. Kitts Wind Resource Assessment	Data was collected for 16 sites during one-week periods and correlated to simultaneous airport data. The 3 sites with projected annual wind speeds over the 7 m/s wind farm target are all over 8.0 m/s.
Barbados Wind Resource Assessment	The wind speed at the southeast coast is 2 m/s higher than the CMI, which is a mile from the west coast. The seasonal variation is very similar but consistently 2 m/s less for every month
Nevis Wind Resource Assessment	Data was collected for 11 sites during one-week periods and correlated to simultaneous airport data. The 2 sites with projected annual wind speeds over the 7 m/s wind farm target are both over 8.0 m/s.

Figure 56 - CMI Wind Data

Various site specific annual average wind speeds are shown on the accompanying graphs. The straight lines on the graphs represent the airport readings.

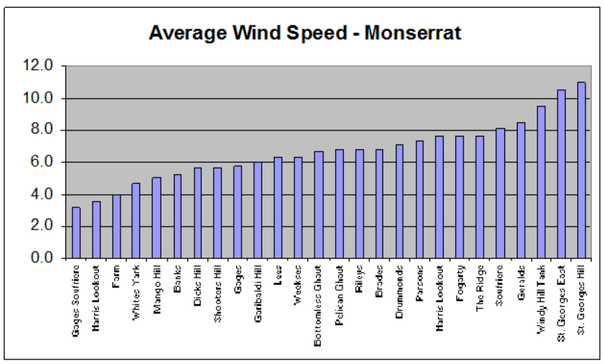


Figure 57 - Montserrat Average Wind Speed

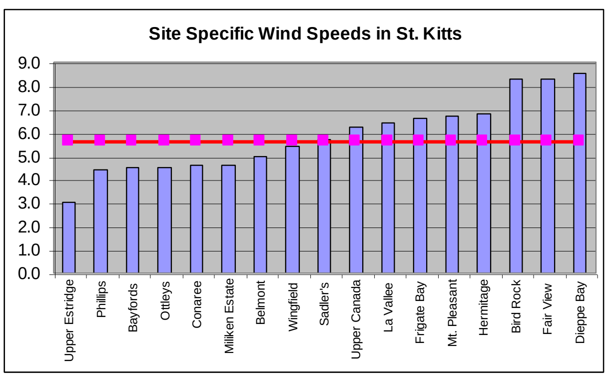


Figure 58 - St. Kitts Wind Speeds

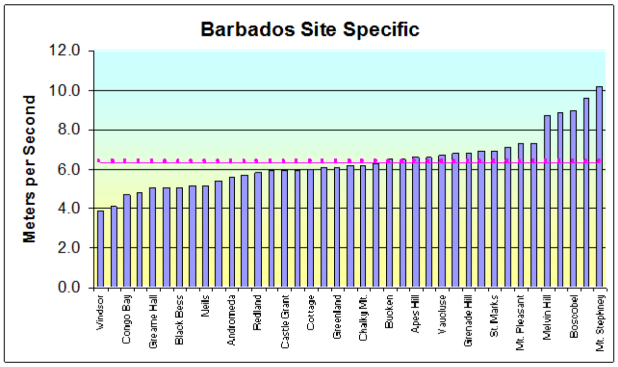


Figure 59 - Barbados Wind Speeds

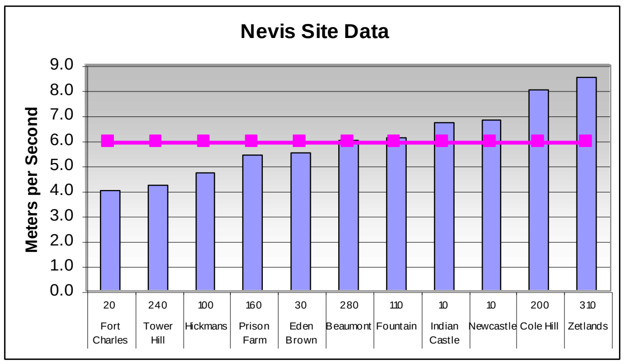


Figure 60 - Nevis Site Data

For the Grenada study, we assume the Dominica wind speeds and apply a site specific ration of 1.2. There was no study of Grenada in either the CMI study of the NASA website.

Computation of Hourly Energy Generation

Once the wind speed is established, the electricity production must be established. The approach to measuring wind resources in our framework begins with evaluation of the technology of wind turbines and conversion of wind energy to electric energy. The process of converting wind to energy is discussed in various articles in Binders 20, 21, and 22. In addition, we have obtained data on the equipment specifications from wind suppliers.

Because of the importance of grants as described in Chapter 3, we have focused on Dutch and Danish Manufacturers in the analysis of suppliers. Strong wind speeds of 15 m/s are the speed at which most turbines reach their capacity. At speeds that are too high (25 m/s), the turbines cut out.

Power Curve of Wind Turbines

A key efficiency measure of a wind turbine is the power curve. This curve measures how much electric power is produced at a given wind speed at an instant in time. The vertical axis measures the capacity factor and the horizontal axis measures wind speed. Most wind turbine manufacturers prominently display the power curve in their brochures (see Binder 19 on wind turbine manufacturers). Because electric power production is a cubic function of wind speed, the power curves illustrate how more incremental power is produced when wind speeds increase. Examples of power curves we have included in the database are shown in the graphs below.

Given a power curve and wind speed data, electricity production can be determined by simply finding various points on the curve. For example, say the wind speed in an hour is 10 m/s. If the power curve implies that wind production is 650KW (from a 1000KW turbine), the electricity production is 650KW and the capacity factor is 65%. The graph with the green background is from a presentation at the CARILEC conference where the presenter emphasized the importance of power curves on capacity factors.

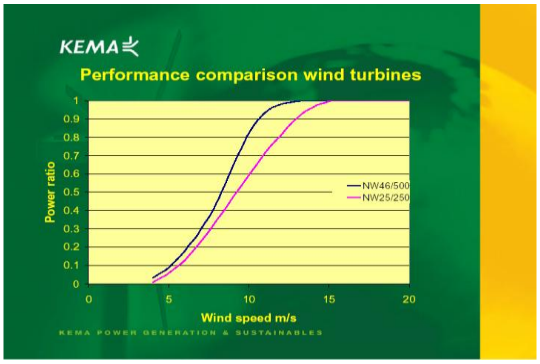


Figure 61 - Performance Comparison of Wind Turbines

To evaluation the effects of a power curve, we have developed a power curve database. This means that different power curves can be combined with different wind speed parameters. The accompanying graphs illustrate different power curves in the database. These power curves can be matched with different wind speed parameters to establish the hour by hour capacity factors which are then used to compute the hourly value of the wind resource.

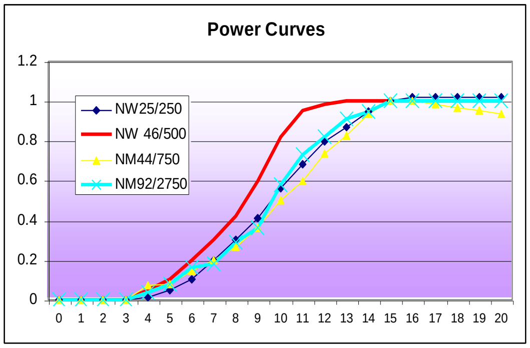


Figure 62 - Power Curves

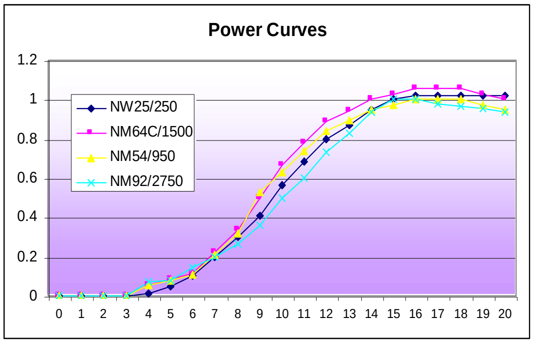


Figure 63 - Power Curves

Net Economic Benefits and Costs of Wind Production

This section describes results of measuring the economic benefits and costs of a 3MW wind project for Grenada included in the pipeline. To model this case, we applied the following assumptions related to wind speeds:

System Characteristics

- 40% Reserve Margin
- Base Case Oil Prices
- 50% Median Speed/50% high speed additions
- Base Case Load Growth

Wind Speeds

- Dominica wind speed is base
- Barbados diurnal patterns
- 20% site specific factor

Power Curve

We assumed a power curve using the NEG Micon NW 45 500 model. This resulted in a capacity factor shown in the graphs below:

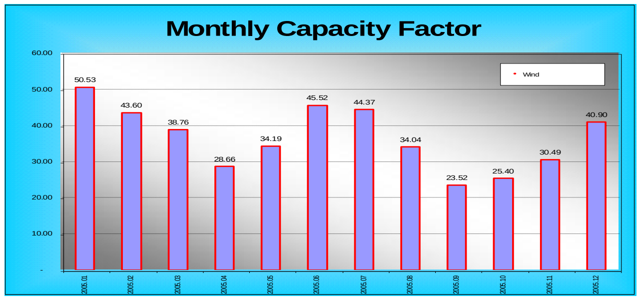


Figure 64 - Monthly Capacity Factor

For a typical day, the capacity factor varies between 40% and 60% as shown in the graph below:

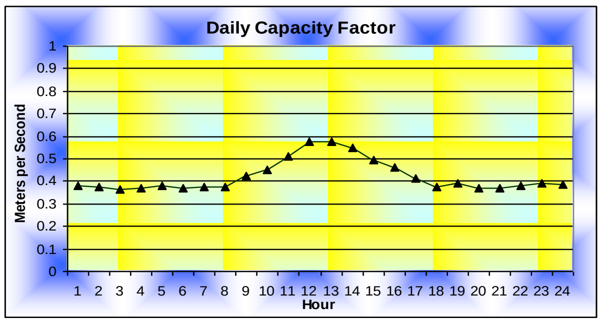


Figure 3 - Daily Capacity Factor

For a month, the distribution of different capacity factors for the wind project is shown in the graph below. The total number of hours is 744. The most frequent capacity factor (the mode) is 44%. There are more than 100 hours for which the capacity factor is 100%.

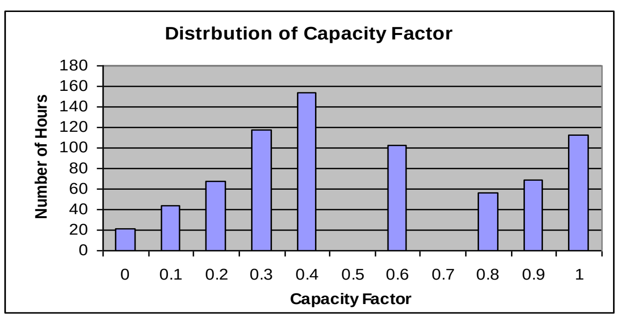


Figure 4 - Distribution of Capacity Factor

The net economic benefits are measured using both a de-rate approach and a Monte Carlo simulation. As was the case for geothermal, the analysis requires assumptions for the PPA price. The PPA model for the Grenada wind project is shown in the table below.

Table 32 - PPA Model

Simulate		Case -->	Grenada Wind			Capactiy Factor		36.6%		PPA Inflation	2.00%	
						Plant Life		20		O&M Inflation	0.00%	
						Base Plant Cost/kW		1,111.07		Debt Repay	15.00	
	Avoided Cost	Equity IRR	Project IRR	Average DSCR	Minimum DSCR	Plant Life Coverage (PLCR)	Minimum PPA Price	Price vs Base	O&M/Plant	Target IRR	Debt/Capital	Cost per kW w/ Constr Interest
Base	72.60	15.27%	9.71%	1.83	1.50	2.10	$ 60.51		5.76%	15.00%	62.13%	$ 1,085.0
Base	72.60	17.17%	10.7%	1.96	1.61	2.26	$ 59.94		5.76%	15.0%	62.13%	$ 1,085.0
No Development Cost	72.60	14.24%	9.1%	1.93	1.60	2.23	$ 66.51		5.76%	15.0%	55.20%	$ 1,290.1
No Grant on Wind Generator	72.60	12.18%	8.3%	1.59	1.33	1.82	$ 71.62		5.76%	15.0%	63.83%	$ 1,389.2
Higher Capacity Factor	72.60	25.21%	15.0%	2.62	2.11	3.03	$ 47.48		8.13%	15.0%	62.13%	$ 1,085.0
Lower Capacity Factor	72.60	14.76%	9.4%	1.79	1.48	2.06	$ 65.20		5.13%	15.0%	62.13%	$ 1,085.0
High O&M Cost and Inflation	72.60	16.80%	10.1%	1.87	1.75	2.13	$ 61.17		4.33%	15.0%	62.13%	$ 1,085.0
Low O&M Cost and Inflation	72.60	22.42%	13.3%	2.35	2.00	2.71	$ 48.05		1.73%	15.0%	62.13%	$ 1,085.0
High O&M Inflation	72.60	13.52%	8.3%	1.66	1.46	1.88	$ 67.24		5.76%	15.0%	62.13%	$ 1,085.0
10 Year Tax Holiday	72.60	20.66%	13.2%	2.18	1.86	2.50	$ 55.60		5.76%	15.0%	62.13%	$ 1,085.0
25 Year Tax Holiday	72.60	21.62%	14.2%	2.35	1.86	2.73	$ 53.75		5.76%	15.0%	62.13%	$ 1,085.0
Accelerated Tax Depreciation	72.60	17.17%	10.7%	1.96	1.61	2.26	$ 59.94		5.76%	15.0%	62.13%	$ 1,085.0
5 Year Tax Life	72.60	19.57%	11.5%	2.02	1.75	2.35	$ 56.68		5.76%	15.0%	62.13%	$ 1,085.0
High Transmission Cost	72.60	18.02%	11.1%	2.03	1.67	2.34	$ 58.26		5.97%	15.0%	61.92%	$ 1,041.9
Longer Plant Life	72.60	17.75%	11.8%	1.93	1.58	2.68	$ 57.82		5.76%	15.0%	62.13%	$ 1,085.0
3% PPA Inflation	72.60	17.91%	11.3%	2.05	1.61	2.38	$ 58.18		5.76%	15.0%	62.13%	$ 1,085.0
15% Environmental Adder	72.60	21.38%	12.9%	2.29	1.88	2.64	$ 52.12		5.76%	15.0%	62.13%	$ 1,085.0
12% IRR Target	72.60	17.17%	10.7%	1.96	1.61	2.26	$ 53.83		5.76%	12.0%	62.13%	$ 1,085.0
18% IRR Target	72.60	17.17%	10.7%	1.96	1.61	2.26	$ 66.46		5.76%	18.0%	62.13%	$ 1,085.0
75% Financing	72.60	17.93%	10.6%	1.83	1.51	2.11	$ 58.75		5.76%	15.0%	66.34%	$ 1,096.2
60% Financing	72.60	15.98%	10.9%	2.28	1.87	2.64	$ 62.22		5.76%	15.0%	53.79%	$ 1,063.6
9% Interest Rate	72.60	15.94%	10.6%	1.77	1.51	2.01	$ 62.62		5.76%	15.0%	62.11%	$ 1,093.2
8 Year Bond Life	72.60	14.55%	10.7%	1.24	1.06	2.21	$ 65.84		5.76%	15.0%	61.95%	$ 1,085.4
Level Payments	72.60	16.23%	10.7%	2.07	1.29	2.25	$ 61.78		5.76%	15.0%	62.13%	$ 1,085.0
No Debt Service Reserve	72.60	17.11%	11.1%	1.83	1.55	2.08	$ 60.29		5.76%	15.0%	62.68%	$ 1,092.0
Worst Case Financing	72.60	13.07%	10.5%	1.23	0.92	2.08	$ 70.31		5.76%	15.0%	57.74%	$ 1,082.3
High PPA Price	72.60	8.78%	7.6%	1.25	0.89	1.62	$ 84.25		5.97%	15.0%	59.29%	$ 1,344.3
Low PPA Case	72.60	23.55%	15.7%	2.51	1.91	3.41	$ 49.54		5.76%	15.0%	62.65%	$ 1,084.1

Given the PPA prices, the following table shows the net economic benefits in the de-rate case. This case assumes the wind project has no capacity value, and since the de-rate deterministic approach is applied, the wind project does not affect loss of load probability and reliability costs.

Table 33 - Net Economic Benefits in the De-Rate Case

Status Quo Case	3	De-rate case - emissions								
Renewable Case	5	Geothermal De-rate Case								
PPA Price ($/MWH)	66									
Economic Analysis of Renewable Projects	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Varible Costs (Fuel and Variable O&M)										
Status Quo Case	10,810,109	15,059,632	13,515,502	14,177,762	15,743,183	18,295,702	19,227,086	20,480,645	22,957,418	24,311,858
Renewable Resource Case	10,810,109	15,059,632	5,242,851	6,382,752	7,623,627	9,803,252	10,552,998	11,681,265	14,922,920	15,871,356
Variable Cost Savings	-	-	8,272,650	7,795,010	8,119,557	8,492,449	8,674,088	8,799,380	8,034,498	8,440,502
Capacity Costs										
Status Quo Case	-	-	1,173,149	1,793,640	2,436,724	2,482,003	3,187,174	3,892,378	4,125,273	5,077,252
Renewable Resource Case	-	-	82	30	609,181	620,524	1,274,831	1,946,092	1,650,129	2,538,541
Capacity Cost Savings	-	-	1,173,067	1,793,610	1,827,543	1,861,479	1,912,342	1,946,286	2,475,144	2,538,711
Cost of Un-Served Energy										
Status Quo Case	-	-	-	-	-	-	-	-	-	-
Renewable Resource Case	-	-	-	-	-	-	-	-	-	-
Reliability Savings	-	-	-	-	-	-	-	-	-	-
Total Savings from Renewable Resouces	-	-	9,445,718	9,588,619	9,947,099	10,353,928	10,586,430	10,745,666	10,509,642	10,979,212
Gross Savings Percent	0%	0%	70%	68%	63%	57%	55%	52%	46%	45%
PPA Price/MWH	66.00	66.00	66.00	66.00	67.32	68.67	70.04	71.44	72.87	74.33
Renewable Energy (GWH)	-	-	96,655	96,665	96,671	96,678	96,682	96,686	96,688	96,689
Total Cost of Renewable Resource	-	-	6,379,223	6,379,922	6,507,907	6,638,514	6,771,588	6,907,303	7,045,584	7,186,547
Net Savings	-	-	3,066,495	3,208,697	3,439,192	3,715,415	3,814,842	3,838,364	3,464,058	3,792,665
Net Savings Percent	0%	0%	23%	23%	22%	20%	20%	19%	15%	16%
Discount Rate	7.0%									
Present Value of Savings over 25 years	$41,764,361		PV of Varible Cost Savings		$93,408,733					
			PV of Capacity Cost Savings		$19,607,478					
kW	12,000.00		PV of Reliabiility Savings		$0					
$/kW	2,083.00		Total Savings		$113,016,211					
Total Cost	$ 24,996,000.00									
			PV of PPA Costs		$71,251,850					
			Net Savings		$41,764,361					

Monte Carlo results are shown below. In this case, the savings are greater as shown below.

Table 34 - Monte Carlo Results

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Status Quo Case	2	Monte Carlo									
Renewable Case	3	Geothermal Monte Carlo									
PPA Price	60										
Economic Analysis of Renewable Projects	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Varible Costs											
Status Quo Case	11,574,957	10,211,779	11,589,142	14,217,517	15,567,341	16,115,406	18,120,689	20,347,451	21,548,782	24,097,391	26,896,916
Renewable Resource Case	11,574,957	10,211,779	11,589,142	8,915,152	8,343,896	11,132,838	12,531,123	11,584,003	12,644,023	13,766,347	16,031,717
Savings	-	-	-	5,302,365	7,223,445	4,982,568	5,589,566	8,763,448	8,904,758	10,331,044	10,865,199
Capacity Costs											
Status Quo Case	-	-	-	-	-	591,862	603,655	615,754	1,355,169	1,382,266	1,409,858
Renewable Resource Case	-	-	-	27	27	28	-	-	-	778,704	794,248
Savings	-	-	-	(27)	(27)	591,834	603,655	615,754	1,355,169	603,562	615,610
Un-Served Energy											
Status Quo Case	172,527	583,054	542,008	1,213,350	2,209,252	675,169	1,263,134	1,950,521	510,570	795,434	2,147,889
Renewable Resource Case	172,527	583,054	542,008	16,974	101,343	398,924	489,514	536,236	1,511,769	280,033	393,666
Savings	-	-	-	1,196,376	2,107,908	276,245	773,620	1,414,284	(1,001,199)	515,401	1,754,223
Total Savings	-	-	-	6,498,714	9,331,326	5,850,647	6,966,840	10,793,486	9,258,728	11,450,007	13,235,032
PPA Price	60.00	60.00	60.00	60.00	61.20	62.42	63.67	64.95	66.24	67.57	68.92
Renewable Energy	-	-	-	91,958	91,975	92,086	93,096	92,900	92,776	93,319	93,837
Total Cost	-	-	-	5,517,459	5,628,853	5,748,358	5,927,674	6,033,446	6,145,940	6,305,526	6,467,371
Net Savings	-	-	-	981,255	3,702,473	102,289	1,039,166	4,760,040	3,112,788	5,144,481	6,767,661
Discount Rate	7.0%										
Present Value of Savings	$37,688,275		PV of Varible Cost Savings		$84,404,941.85						
			PV of Capacity Cost Savings		$7,129,587.33						
kW	12,000.00		PV of Reliabiility Savings		$4,321,568.77						
$/kW	2,083.00		Total Savings		$95,856,097.94						
Total Cost	$ 24,996,000.00										
			PV of PPA Costs		$58,167,822.55						
			Net Savings		$37,688,275.40						

Section 5: Capacity Credit of Wind Resources

Perhaps the most complex aspect of modelling wind resources is quantifying the stochastic nature of wind and capacity credits. This section describes how the avoided cost modelling analysis can be used to consider the issue of whether wind projects are able to off-set the amount of capacity that is added to a system. We recognize the reluctance of companies to include capacity costs as avoided cost. This is demonstrated by the following survey response from Grenlec:

> "We are of the view that – at least for initial development – the addition of RET would NOT provide a basis for avoided plant addition costs. Therefore, avoided cost of plant cannot be factored into the analysis."

The question of avoided capacity is straightforward for geothermal and bagasse technologies. In these cases, the addition of a renewable resource clearly off-sets diesel or other capacity additions that otherwise would occur from the necessity to meet growing load. For geothermal plants, the availability factor is generally estimated to be higher than the availability factor of diesel plants. This implies that the capacity credit should be greater than 100% for geothermal. Stated differently, less than 1 KW of geothermal capacity equates to 1 KW of diesel capacity. For bagasse, the technology should generally have a similar outage rate as diesel and the capacity credit should be 100%.

Determining how much capacity can be off-set when a wind farm is added to a system is more complex than geothermal or bagasse because the energy generation from wind turbines is variable and dependent on the wind. Even if the machine has a 100% availability factor, if the wind does not blow at times of the year when capacity is needed, the wind turbine does not off-set the need for new capacity. Therefore, to assess the

capacity value of wind, one must evaluate how wind affects the reliability of a system. In the remainder of this section we consider issues associated with measuring the capacity value of wind and the stochastic nature of wind. We first discuss general issues associated with measuring capacity value and loss of load probability. Next, we discuss how to model the effect of wind resources on loss of load probability. In the third section, we present results of wind resource modelling in the case of Grenada. Finally, we use the analysis to measure the capacity value of wind energy resources in the Caribbean.

Section 6: Sensitivity Analysis

A number of assumptions and modelling techniques can have an effect on measurement of the economic viability of wind resources. We present the following sensitivity cases:

- Using the de-rate method rather than Monte Carlo simulation method
- Using higher and lower fuel price scenarios
- Using different wind parameters
- Using different approaches to measure stochastic wind speeds
- Using different wind turbine technologies
- Using different financial parameters

We have not developed all of these sensitivity cases for the different systems. However, during the workshop, participants will be instructed on how to develop the scenarios. Sensitivity cases for higher and lower oil prices are shown in the table below.

Table 35 - Sensitivity Case Lower Oil Price

Status Quo Case	8	High Fuel Price Derate									
Renewable Case	9	Wind Case High Fuel									
PPA Price	60										
Economic Analysis of Wind Projects	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Varible Costs											
Status Quo Case	10,296,852	9,838,506	11,034,112	14,393,103	16,741,013	19,231,681	21,735,423	24,533,035	28,206,476	31,594,383	35,423,998
Wind Resource Case	10,296,852	9,838,506	11,034,112	13,484,512	15,606,961	18,015,594	20,440,478	23,160,941	26,768,578	30,130,858	33,936,035
Savings	-	-	-	908,591	1,134,051	1,216,087	1,294,945	1,372,094	1,437,898	1,463,525	1,487,963
Capacity Costs											
Status Quo Case	-	14,810	104,715	312,431	505,147	753,019	986,249	1,253,351	1,555,962	1,870,137	2,222,430
Wind Case	-	14,810	104,715	312,431	505,147	753,019	986,249	1,253,351	1,555,962	1,870,137	2,222,430
Savings	-	-	-	-	-	-	-	-	-	-	-
Un-Served Energy											
Status Quo Case	-	-	-	-	-	-	-	-	-	-	-
Wind Case	-	-	-	-	-	-	-	-	-	-	-
Savings	-	-	-	-	-	-	-	-	-	-	-
Total Savings	-	-	-	908,591	1,134,051	1,216,087	1,294,945	1,372,094	1,437,898	1,463,525	1,487,963
PPA Price	60.00	60.00	60.00	60.00	61.20	62.42	63.67	64.95	66.24	67.57	68.92
Wind Energy	-	-	9,632	9,632	9,632	9,632	9,632	9,632	9,632	9,632	9,632
Total Cost	-	-	577,945	577,945	589,504	601,294	613,320	625,586	638,098	650,860	663,877
Net Savings	-	-	(577,945)	330,646	544,548	614,793	681,625	746,508	799,800	812,665	824,086
Present Value of Savings	$6,829,857.67										
kW	3,000.00										
$/kW	1,200.00										
Total Cost	$ 3,600,000.00										

Table 36 - Sensitivity Case Higher Oil Price

Status Quo Case	8	High Fuel Price Derate									
Renewable Case	10	Wind High Fuel Derate									
PPA Price	60										
Economic Analysis of Wind Projects	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Varible Costs											
Status Quo Case	10,296,852	9,838,506	11,034,112	14,393,103	16,741,013	19,231,681	21,735,423	24,533,035	28,206,476	31,594,383	35,423,998
Wind Resource Case	10,296,852	9,838,506	11,034,112	13,567,012	15,757,457	18,183,092	20,623,526	23,358,210	26,957,265	30,322,975	34,123,402
Savings	-	-	-	826,091	983,556	1,048,589	1,111,897	1,174,825	1,249,210	1,271,408	1,300,596
Capacity Costs											
Status Quo Case	-	14,810	104,715	312,431	505,147	753,019	986,249	1,253,351	1,555,962	1,870,137	2,222,430
Wind Case	-	14,810	104,715	245,579	436,954	683,458	915,302	1,180,982	1,482,144	1,794,843	2,145,633
Savings	-	-	-	66,852	68,193	69,561	70,947	72,369	73,818	75,294	76,797
Un-Served Energy											
Status Quo Case	-	-	-	-	-	-	-	-	-	-	-
Wind Case	-	-	-	-	-	-	-	-	-	-	-
Savings	-	-	-	-	-	-	-	-	-	-	-
Total Savings	-	-	-	892,943	1,051,749	1,118,150	1,182,844	1,247,194	1,323,028	1,346,702	1,377,393
PPA Price	60.00	60.00	60.00	60.00	61.20	62.42	63.67	64.95	66.24	67.57	68.92
Wind Energy	-	-	9,632	9,632	9,632	9,632	9,632	9,632	9,632	9,632	9,632
Total Cost	-	-	577,945	577,945	589,504	601,294	613,320	625,586	638,098	650,860	663,877
Net Savings	-	-	(577,945)	314,998	462,245	516,856	569,524	621,608	684,930	695,842	713,516
Present Value of Savings	$6,016,766.14										
kW	3,000.00										
$/kW	1,200.00										
Total Cost	$ 3,600,000.00										

In the case with alternative wind profiles, the PPA price is changed because fixed costs are spread over different amounts of energy. If the energy production is increased, the PPA price declines. The annual capacity increases from 36.6% to 50.87%. The higher capacity factor allows the PPA price to be reduced from $60/MWH to about $50/MWH as illustrated on the following table.

Table 37

Simulate		Case -->	Grenada Wind			Capactiy Factor		50.0%		PPA Inflation	2.00%	
						Plant Life		20		O&M Inflation	2.00%	
						Base Plant Cost/kW		1,045.17		Debt Repay	15.00	
	Avoided Cost	Equity IRR	Project IRR	Average DSCR	Minimum DSCR	PLCR	Minimum PPA Price	Price vs Base	O&M/Plant	Target IRR	Debt/Capital	Cost per kW Incl IDC
Base	72.60	14.89%	10.39%	2.07	1.76	2.39	$ 48.99		8.37%	15.00%	57.35%	$ 783.6
Base	72.60	24.17%	15.7%	2.95	2.49	3.41	$ 49.17		8.37%	15.0%	57.35%	$ 783.6
No Development Cost	72.60	20.48%	13.1%	2.76	2.33	3.20	$ 54.06		8.37%	15.0%	50.51%	$ 777.4
No Grant on Wind Generator	72.60	18.40%	12.3%	2.29	1.95	2.64	$ 58.00		8.37%	15.0%	59.16%	$ 1,087.1
Higher Capacity Factor	72.60	31.09%	19.8%	3.72	3.11	4.31	$ 42.22		10.88%	15.0%	57.35%	$ 783.6
Lower Capacity Factor	72.60	22.16%	14.6%	2.75	2.32	3.18	$ 51.78		7.70%	15.0%	57.35%	$ 783.6
High O&M Cost and Inflation	72.60	25.30%	16.0%	2.94	2.72	3.37	$ 48.39		6.29%	15.0%	57.35%	$ 783.6
Low O&M Cost and Inflation	72.60	31.09%	19.8%	3.75	3.14	4.34	$ 35.27		2.51%	15.0%	57.35%	$ 783.6
High O&M Inflation	72.60	21.97%	13.9%	2.58	2.33	2.94	$ 54.46		8.37%	15.0%	57.35%	$ 783.6
10 Year Tax Holiday	72.60	30.30%	19.8%	3.42	3.00	3.96	$ 45.55		8.37%	15.0%	57.35%	$ 783.6
25 Year Tax Holiday	72.60	30.88%	20.6%	3.74	3.14	4.34	$ 44.37		8.37%	15.0%	57.35%	$ 783.6
Accelerated Tax Depreciation	72.60	24.17%	15.7%	2.95	2.49	3.41	$ 49.17		8.37%	15.0%	57.35%	$ 783.6
5 Year Tax Life	72.60	28.05%	17.2%	3.02	2.61	3.56	$ 46.53		8.37%	15.0%	57.35%	$ 783.6
High Transmission Cost	72.60	25.17%	16.3%	3.08	2.59	3.57	$ 47.90		8.69%	15.0%	57.11%	$ 743.7
Longer Plant Life	72.60	24.16%	16.3%	2.91	2.44	4.03	$ 47.90		8.37%	15.0%	57.35%	$ 783.6
3% PPA Inflation	72.60	24.77%	16.3%	3.10	2.49	3.61	$ 47.73		8.37%	15.0%	57.35%	$ 783.6
15% Environmental Adder	72.60	29.17%	18.6%	3.50	2.94	4.05	$ 42.75		8.37%	15.0%	57.35%	$ 783.6
12% IRR Target	72.60	24.17%	15.7%	2.95	2.49	3.41	$ 44.77		8.37%	12.0%	57.35%	$ 783.6
18% IRR Target	72.60	24.17%	15.7%	2.95	2.49	3.41	$ 53.89		8.37%	18.0%	57.35%	$ 783.6
75% Financing	72.60	26.30%	15.6%	2.57	2.17	2.97	$ 47.70		8.37%	15.0%	65.50%	$ 787.3
60% Financing	72.60	23.30%	15.8%	3.18	2.68	3.69	$ 49.88		8.37%	15.0%	53.29%	$ 781.8
9% Interest Rate	72.60	23.26%	15.7%	2.67	2.30	3.04	$ 50.76		8.37%	15.0%	57.34%	$ 790.6
8 Year Bond Life	72.60	21.12%	15.7%	1.88	1.63	3.35	$ 52.66		8.37%	15.0%	57.18%	$ 783.9
Level Payments	72.60	23.08%	15.7%	3.07	1.99	3.38	$ 50.46		8.37%	15.0%	57.35%	$ 783.6
No Debt Service Reserve	72.60	24.39%	16.3%	2.76	2.36	3.13	$ 49.36		8.37%	15.0%	57.84%	$ 789.8
Worst Case Financing	72.60	19.69%	15.5%	1.76	1.31	2.93	$ 55.08		8.37%	15.0%	57.18%	$ 791.0
High PPA Price	72.60	14.49%	11.6%	1.68	1.21	2.17	$ 65.74		8.69%	15.0%	58.98%	$ 1,055.9
Low PPA Case	72.60	32.45%	21.8%	4.02	3.23	5.39	$ 41.42		8.37%	15.0%	57.80%	$ 782.9
Base PPA Case	72.60	22.58%	17.5%	1.86	1.71	3.32	$ 59.36		8.69%	20.0%	56.93%	$ 755.4

Probability of Hourly Wind Production

The above discussion described how regional hourly wind data, combined with annual site specific wind speed data, combined with different wind technologies can be used to measure the energy production of a wind farm in any particular hour for a historic period.

Project distributions of hourly capacity factors drive the reliability modelling. Our approach to quantify the effect of a wind farm on loss of load probability uses two approaches as follows:

1. Use actual hourly wind profiles to measure the probability of wind production in an historic hour. For example, if the actual wind production is zero in a high load hour, the wind farm will not reduce the LOLP.

2. Use simulated wind production where the standard deviation of wind generation is used to create a probabilistic measurement of how much generation will be available from the wind farm. For example, in any particular hour, there is some probability of wind energy production.

Measurement of Capacity Value

The capacity value of the Wigton Wind Farm is illustrated in the figure below. The diagram suggests that the value of wind should be gauged by considering the effect of the wind farm on loss of load probability. The conclusion of the analysis was that the wind farm should be given 35% capacity credit. This is the approximate expected capacity factor of the project. Using the model that will be provided to CARICOM, a similar approach can be developed. The model first establishes LOLP without any renewable resources – in the base case. Next, renewable resources are added in the model. This will reduce the LOLP if no capacity credit is attributed to the renewable resources. Finally the renewable resource is given capacity credit while the LOLP is the same as the status quo case.

Status quo case → LOLP
Add wind to status quo → Reduced LOLP
Reduce diesel capacity in added wind case → Original LOLP

In the above diagram, the reduced amount of diesel capacity that can be added because of the wind resource reduces LOLP. In order to apply the LOLP concept, one must define loss of load probability and one must understand how LOLP measures the value of capacity, and one must model the impacts of wind production on LOLP.

LOLP, Reserve Margin, and N-2

The notion of capacity value is directly tied to the issue of reliability. An unreliable system has many power outages because of generating plant failures and/or insufficient generating capacity to meet load. Two ways to improve reliability are to increase the amount of generating capacity or to improve the availability of existing plants. Reliability is often measured using a reserve margin which computes the amount of capacity that exists at the time of the system peak. If the reserve margin is 20%, then if all capacity is available, 20% of the capacity can be unavailable at the time of the system peak and demand can still be met. If all units have similar availability then the reserve margin is a reasonable way to measure reliability. If there are different resources with varying availability, the reserve margin does a poor job in measuring reliability.

An alternative measure of reliability is the loss of load probability. This statistic measures the probability of not having enough available capacity to meet demand. The LOLP can be measured in a variety of ways, taking account of the probability of a set of generating units being unavailable in a particular hour. The method applied in the model provided to CARICOM is to simulate the probability of multiple plants not operating. In simulations where the load exceeds available capacity, a loss of load hour is recorded. The loss of load hours are summed over the year and averaged across simulations.

A third way to measure reliability is to assign a monetary value to times at which load cannot be met with available resources. This is similar to LOLP where the cost of unserved energy is applied to all situations where the loss of load probability is greater than zero. The approach we have used combines the LOLP and the unserved energy concepts in measuring capacity value. In this approach, the capacity value of wind resources is a function of the availability of diesel and other non-traditional plants as compared to the probability that electricity from a wind farm will be produced in any given hour.

Modelling the Stochastic Process of Wind Production

As discussed above, we have developed two methods to quantify the amount of wind production. The first method involves inputting hourly profiles for wind production for each of the 8,760 hours in a year. If the wind production reduces the amount of load that must be met with diesel plants, the LOLP improves. The wind energy production in a month is illustrated in the graph below.

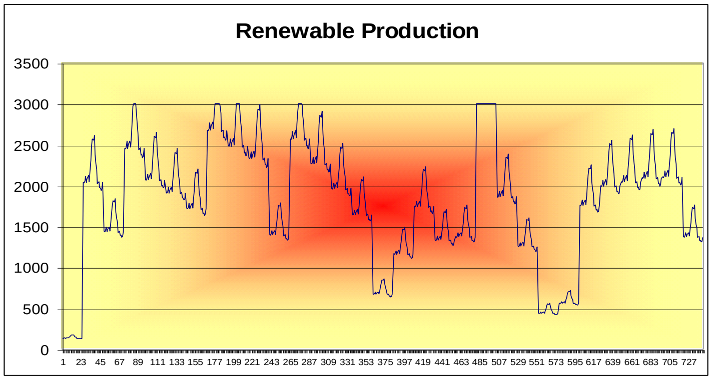


Figure 65 - Renewable Production

The second method involves establishing a typical daily profile for wind production and allowing the actual production to vary according to a probability distribution. The second graph shows how the hourly distribution varies after allowing the wind to vary on a stochastic basis as defined by the standard deviation of capacity factors.

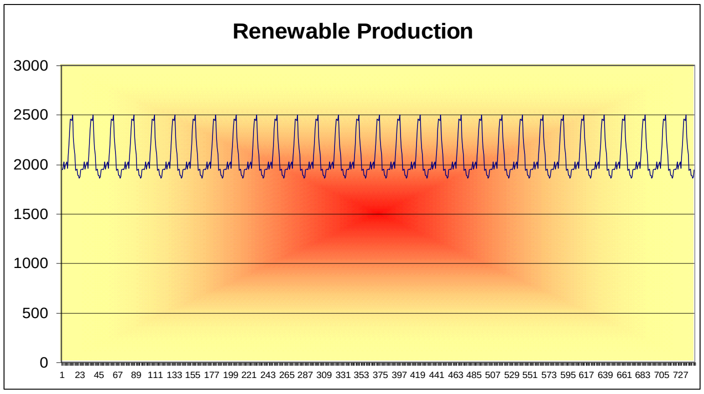


Figure 66 - Renewable Production

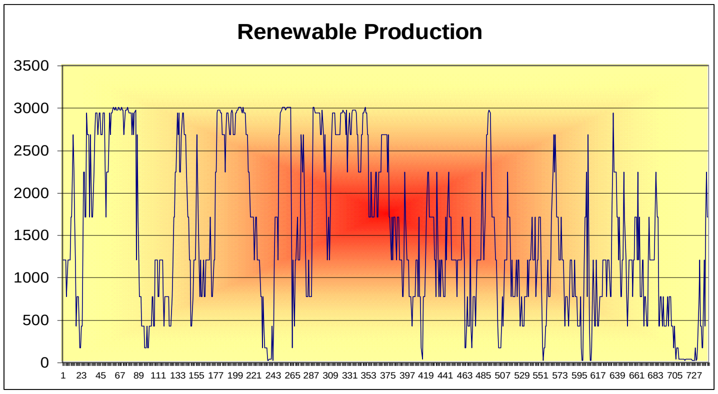


Figure 67 - Renewable Production

Capacity Value Results in the Grenada Case Study

We illustrate how wind generation has capacity value using the case of Grenada. We first describe results using the hour by hour profiles. Then we discuss results using the probabilistic method. In the status quo case with an outage rate of 12.8% for diesel plants and a reserve margin of 40%, the loss of load probability on a year by year basis is illustrated on the accompanying graph.

In the next scenario, wind production is added and it is given no capacity credit. In this case, the amount of capacity required to meet the reserve margin is the same as in the status quo case. Since the wind energy is available, the loss of load probability is reduced. The accompanying graph illustrates the reduction in LOLP and un-served energy from adding the wind resources. This graph demonstrates that wind should be given some capacity credit.

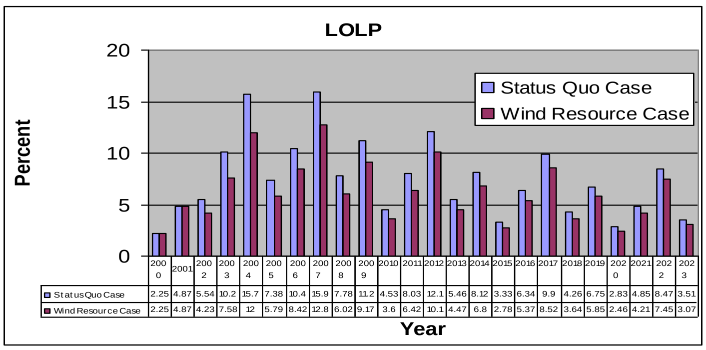


Figure 68 - Reduction in LOLP and Un-Served Energy

2002

Chapter V - Rate Impact Analyses

Introduction

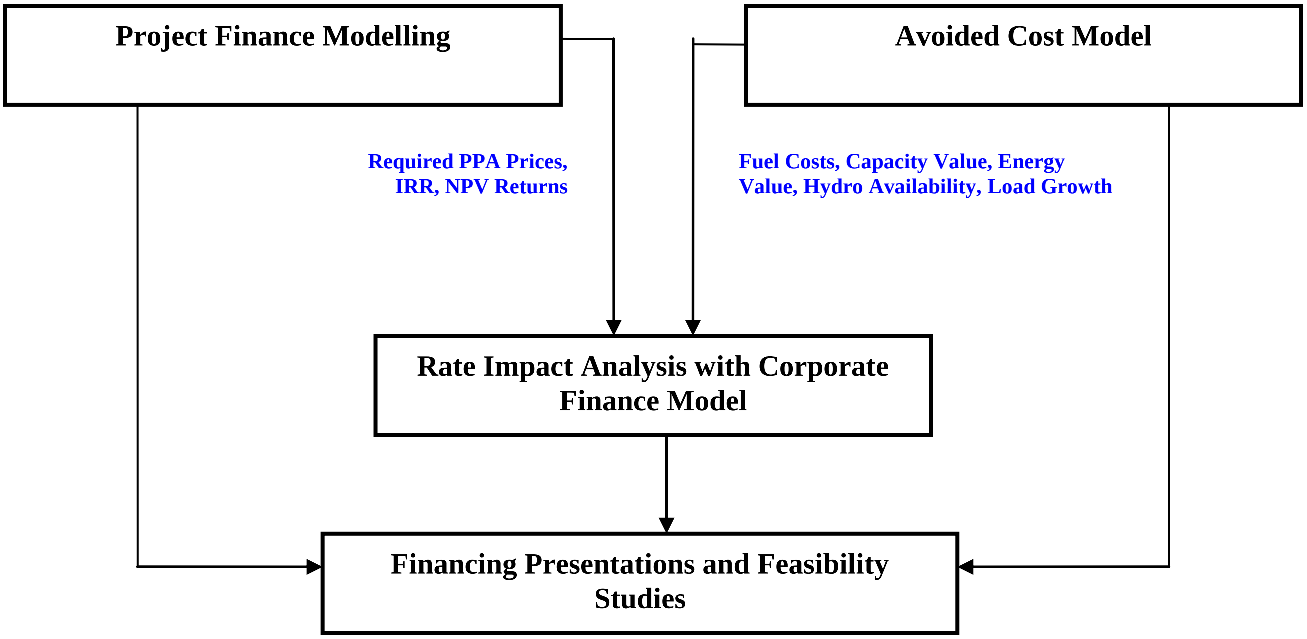
Part of the analysis in this consultancy for CARICOM involves rate impacts of renewable technologies in the fourteen CARICOM countries. The rate impact was discussed as follows in the work plan:

> "After the hour-by-hour forward marginal energy costs have been established and the contract structure for the renewable energy project has been defined, the utility corporate financial model can be used to quantify the effect of the renewable technologies on retail rates and utility finances. The model uses alternative financial criteria and historic financial statement data to project retail rates for various types of utility companies. As with the system simulation model and the project finance model, this software will be provided to CARICOM as part of ADICA's engagement."

The rate impact analysis compares future retail rates in a scenario that includes renewable resources, to rates under a status quo case where no renewable resources are deployed. The analysis is performed for each utility company in the region for which adequate, publicly available data exists. The rate impact analysis in this chapter addresses how deployment of renewable resources affects consumer utility bills and other issues. It also provides extensive data that can lead to a more transparent, more comprehensive process for evaluating renewable resources in the region.

Much has been made of the high electric rates and high avoided costs in the Caribbean region as justification for renewable projects. For example, in describing the potential for geothermal plants in the region, Gerald Hutter stated: "In virtually all of the islands, generation (predominantly diesel-fuel, with some hydro), transmission and distribution range between $0.12/KWH – $0.15/KWH. It is important to note that while few of the utility companies have accurate accounting of their real costs…." This quote demonstrates that little objective analysis of what drives the high rates and how much cost can realistically be avoided through deployment of renewable resources.

The rate impact modelling described in this chapter is one of three models that together evaluate the overall economic viability of renewable energy technologies in the Caribbean. In addition, outputs of the rate impact model meet two important requirements for developers seeking financing: background market data on loads, capacity, generation, sales and losses, and information on the financial viability of the off-taker. Together with project models and avoided cost models, the rate impact analysis evaluates whether renewable energy technology projects are economically and financially viable. The way the rate impact analysis fits together with other parts of the consulting project is illustrated in the diagram below.



The rate impact analysis involves collecting data, developing models of projected rates with and without deployment of renewable resources, and presenting the results for each analysed utility company in the region. We have been able to collect a significant portion of the necessary data for a rate impact analysis from the annual reports submitted by utility companies in the region, and we have completed financial models for those companies for which we have data. However, there is some data necessary for refinement of the models that is being sought through the utility surveys (for example, the dates of plant retirements and planned new capacity). We have made tentative assumptions with respect to this data, and we will refine the models once we receive more comprehensive information.

The rate impact discussion below is divided into five sections. The first section reviews objectives of the rate impact analysis; the second section describes the analytical modelling process and key equations used in the rate impact model; the third section describes data and assumptions used in the model; the fourth section walks through the rate analysis model using one company – Dominica Electricity Services Ltd. The final section discusses how we can deliver the rate impact model so that it can be used by developers, financiers, utility companies and governments in the region to assist in the development of economically viable renewable resources.

The table below lists the status of rate impact analysis completed to date from annual report data:

Table 38 - Status of Rate Impact Analysis

Country	Utility	Annual Report Received	Utility Survey Received	Years of Historic Data
Antigua and Barbuda	Antigua Public Utilities Authority	No	Yes	
The Bahamas	Bahamas Electricity Corporation (BEC)	Yes	Yes	1991-2000
Barbados	BL&P	Yes	No	1997-2001
Belize	Belize Electricity Ltd (BEL)	Yes	Yes	1996-2001
British Virgin Islands	B.V.I. Electricity Corp.	Yes	Yes	1993-1999
Dominica	Domlec	Yes	Yes	1997-2001
Grenada	Grenlec	Yes	Yes	1997-2001
Guyana	Guyana Power & Light	Yes	No	1999-2001
Jamaica	JPSCo	Yes	No	1997-2001
Montserrat	Montserrat Electricity Services	Yes	Yes	Not enough information
St. Kitts and Nevis	Nevlec	No	No	
St. Lucia	Lucelec	Yes	No	1992-2001
St. Vincent & the Grenadines	Vinlec	Yes	No	1996-2001
Suriname		No	No	
Trinidad & Tobago	T&TEC	No public report available	No	
Trinidad & Tobago	PowerGen	No	Yes	
Turks and Caicos Islands	Turks & Caicos Utilities Ltd.	No	No	

As with other parts of the analysis, our intention is that the rate impact modelling should not simply to provide a report that will collect dust. Rather, as with the project model and the avoided cost model, we have developed the models and so that they can be used as tools for continued analysis in the future. Through interaction in future workshops, we hope that developers, utility companies, and the CARICOM staff will be able to use the models and the approach outlined in this report in the future as more renewable resource projects are evaluated.

Binder Library Resources

The assumptions, data, and background information that support the rate impact analysis are documented in the "CARICOM Renewable Resource Library." This library includes different binders that cover subjects ranging from tax policy for each country, to background articles on geothermal plants, to actual Power Purchase Agreement (PPA) contracts around the world. The binders include a number of articles, reports, data, contact data, and interview results from our analysis. Binders used in the rate impact analysis include Binders 2 and 3, Annual Reports; Binder 13 and 14, Fuel costs; and Binder 18, Diesel Suppliers and Information. The list of materials included in each binder is included in Volume III. The contents of the binders are also available on CD's which could be distributed to utility companies, developers, financiers and government agencies in the region.

Section 1: Objectives of the Rate Impact Analysis

The rate impact analysis was discussed in the kick-off meeting, where steering committee members made the point that economic impacts on the countries are an important issue in the evaluation of renewable technologies. One important economic impact is the effect of renewable resources on retail rates. Other impacts include the effect on jobs, the effect on the environment, and the effect on foreign exchange used to purchase imported oil.

The rate impact analysis completes a few different objectives for CARICOM in the development of renewable resources:

- First, the rate impact analysis quantifies the effect of the development of renewable resources on how much consumers pay in electric bills.

- Second, the analysis provides approximate avoided cost computations using public data and a consistent framework across utility companies. For companies that have not or will not provide responses to the utility survey, the analysis provides "pro forma" avoided fuel and variable O&M cost calculations, which are two of the four components of avoided costs. (The other components are avoided capacity costs and avoided losses).

- Third, the rate impact analysis provides historic data on loads, capacity, fuel costs, and generation operation and maintenance costs that are used in the more detailed avoided cost analysis.

- Fourth, the financial models in the rate impact analysis develop financial viability measures of utility companies to support project financing -- information on the financial viability of the off-taking utility company.

- Fifth, the rate impact analysis measures societal effects of renewable resources – reductions in the amount of fuel purchased and emissions from diesel oil plants.

- Sixth, the rate impact analysis measures the risks of reliance on renewable resources relative to conventional technologies by measuring the sensitivity of results with respect to oil price changes and resource deployment.

- Seventh, we hope the usefulness of this analysis will prompt all companies to complete the utility survey to prompt more detailed measurement of avoided cost. Data from the report may be useful in explaining the potential benefits of renewable resources and the contributions that CARICOM is making.

Each of these objectives is discussed in more detail below.

1. <u>Impact of Renewable Resource Deployment on Electric Bills</u>

The rate impact analysis compares retail rates in a status quo case with rates in that result if renewable energy technology (RET) is deployed. The renewable cases are developed by changing the status quo case to add projects in the CARICOM pipeline, which reduce energy production and/or reduce new capacity additions from diesel plants. The comparisons between status quo cases and renewable cases determine the economic benefits or costs of deploying renewable resources. The economic evaluation is made under alternative assumptions with respect to renewable resource assessments (e.g. capacity factor of wind projects), oil prices, avoided capacity cost for renewable technologies, load growth, and other items. We investigate the viability of projects without subsidies from

indigenous governments. If the projects are not viable without subsidies, the analysis can be used to evaluate the type of subsidy that is most appropriate. For example, the status quo case for Dominica assumes that future load growth is met with added diesel capacity, while there are three renewable cases: one with a 3MW wind project, one with a 12 MW geothermal project, and one with both the wind project and the geothermal project.

If renewable projects are economically viable and PPA prices are derived from project models, the rate impact analysis will illustrate the rate reduction benefits to the public. These environmental and foreign exchange benefits are added to the model to support government policy including tax incentives (e.g. a tax holiday for RET resources), and financial support mechanisms such as sovereign guarantees to support the programs.

2. ***<u>Approximate Avoided Cost Calculations</u>***

One of the primary objectives of this consulting project is developing meaningful avoided cost benchmarks for each utility in CARICOM. As part of our background research, we have held discussions with developers about the major impediments to development and what services they would like most from the CARICOM Secretariat. Our discussions confirm that two areas are most important – obtaining financing and negotiating PPA's. The response from many developers was that having avoided cost and other information used in a more transparent and objective process for resolving PPA prices is essential. The accompanying text box recounts some of our findings from discussions with project developers.

Importance of Avoided Cost Modelling to Developers

Bevin Etienne, a developer of two potential wind projects in Dominica, mentioned that development is restricted because of limited discussions on PPA's with Dominica Electricity Services Limited (Domlec) until the economy improves. He told us that he is very interested in avoided cost modelling and would like to see the results when they are finished. Another example of the importance of developing objective information on avoided cost is illustrated by the Wigton Wind Farm case, where according to Raymond Wright the PPA negotiation lasted for five years. Problems in establishing pricing in PPA's were also confirmed by Roy Kolader of Delta Caribbean who is developing a wind project in Guyana.

We believe that CARICOM can offer significant technical assistance in the region by providing objective and transparent data on utility avoided costs and project production costs for use by developers and utility companies. The rate impact analysis and the project finance modelling perform this task. If PPA prices are based on avoided fuel and variable operation and maintenance (O&M) costs, and if the project is economic using these prices (see the project finance modelling

chapter), then rates will be reduced for customers, the utility avoids added costs, and the project meets its IRR.

Data on average diesel fuel cost per MWH generated, and statistics on variable O&M, are essential inputs to the analysis. Annual report data for most companies in the region provide the fuel expense, the MWH generation, and the non-fuel generation expenses. This data can be used to develop approximate avoided costs. Comparison of avoided costs with required PPA prices (discussed in the project finance model analysis) provides a transparent basis for PPA prices that will be reasonable.

3. ***Data consolidation for Avoided Cost Analysis***

The rate impact analysis uses financial data, as well as data on capacity, peak load, electricity sales, generation costs and other items, from each utility company. With this data, the model projects retail rates, fuel costs, and the financial condition of the utility company. This analytical process results in a database that aggregates load data, capacity data, fuel cost data, financial data and exchange rate data for each country that is modelled. The consolidation of data provides important input to the more detailed hourly avoided analysis that will be completed as we receive responses to our utility company survey. The data also has value in and of itself, its use by developers in providing background data and off-taker stability for potential lenders.

4. ***Financial Analysis of Utility Companies in Support of Developers***

The value of PPA contract depends in part on the credit quality of the utility company. A contract between a developer and a utility company may have fixed prices, a long tenor, and result in stable cash flow for the project developer. If a utility company would default on loans or declare bankruptcy, the PPA contract would probably also not be honoured. In other words, if the utility files for bankruptcy, the PPA contract has no value. If a utility company is on the verge of bankruptcy, the developers will generally have a more difficult time in arranging financing because the value of the PPA contract in financing will be less. Therefore, in making presentations to bankers on a potential RET project, developers will generally have to provide information on the credit quality of the utility company (also known as the off-taker). The retail rate impact analysis will provide this information for the developers and will be a useful tool.

5. ***Demonstration of Tools to Promote CARICOM's Work***

Data collected for the rate impact analysis also allows various comparisons of utility companies across the region. For example, average fuel costs per MWH, reserve margins, financial performance, peak load and retail rates are compared in the next section of the chapter. Consistent with objectives to achieve a

transparent process for renewable analysis, the rate impact analysis is based purely on public data and uses objective modelling techniques that are uniformly applied across utility companies. We hope that when utility companies see the presentation of data and the mechanics of our approach they will be willing to work with us in the more detailed avoided cost part of the analysis described in Chapter 4. As explained in the final section of this chapter, we are prepared to deliver the modelling effort through interactive workshops with utility companies, developers, bankers and government officials.

Section 2: Results of the Rate Impact Analysis

This section presents results of the rate impact analysis. We first review the status of the rate impact analysis for each utility company in the region. Next, we show comparative results for the status quo case for each utility company (the historic and projected retail rates, the historic and projected average fuel expense per MWH, the historic and average non-fuel generating cost per MWH, the historic and projected financial condition of each company).

1. *Status of Rate Impact Model*

We have completed financial models for each of the utility companies for which we have financial data. We have not been able to obtain annual reports for Antigua & Barbuda, Cuba, St. Kitts & Nevis, Suriname, and Turks & Caicos. The annual report for T&TEC is not published. The rate impact analysis is not finalized, because we are awaiting responses to our comprehensive survey that requests hourly demand data, detailed capacity data, and projected capacity planning information). However, we have prepared representative results that demonstrate how the model works, and the results (based on region-specific data) can be used even if we do not receive more complete data.

2. *Results of the Rate Impact Modelling in the Status Quo Case*

Caribbean utility companies tend to report a significant amount of data in their annual reports, but the data is in different currencies and statistics such as average retail rates, the cost of fuel per MWH, reserve margins and financial ratios are not presented. These and other statistics are computed in the rate impact analysis.

The following nine graphs (and the accompanying text) summarize some of the most important statistics relevant to the economic and financial viability of renewable projects.

- The first graph shows the average revenue per kWh (weighted average retail rates across customer classes) in the year 2001 or 2000 for each utility company. The statistics are all converted to US$/KWH.

- The second graph illustrates the projected average revenue per kWh for Domlec in the status quo case with three alternative fuel price scenarios – the base case scenario and the high fuel price scenario.

- The third chart presents the year 2000 average fuel expense divided by the fossil fuel generation for each utility company, which is a rough indication of the avoided fuel cost – one of the four components of avoided cost.

- The fourth set of graphs illustrates the trends in fuel cost from 1992 through 2001 as compared to the world price of oil.

- The fifth graph shows the non-fuel generation expense divided by the kWh generated as background for avoided variable O&M cost analysis. Avoided variable O&M cost is a component of the non-fuel generation expenses for which data is difficult to obtain.

- The sixth graph shows the reserve margin of each utility company (the firm capacity divided by the peak load). This analysis provides background with regard to the value of RET in reducing the amount of new capacity, or the avoided capacity cost.

- The seventh graph shows the interest coverage ratio for each utility company in the year 2000. Interest coverage measures the financial stability of utility companies and the ability of the companies to meet PPA obligations or to finance renewable projects.

- The eighth graph shows the debt to capital ratio for each utility company to provide additional background on the financial health of each utility company, who are the off-takers in PPA contracts, or financers of renewable projects.

- The ninth graph shows the return on investment for each utility company in the region for the year 2000 or 2001. The graph provides background on the rate increase requirements.

The results and implications for each of these graphs are discussed below:

Retail Rates

The comparison of retail rates shows that average revenue per kWh varies between 25 cents per kWh for Domlec to 11 cents per kWh for JPSCo. Average revenue/KWH measures the actual revenue collected by companies from retail rates, divided by total KWH electricity sales. These computations include all customers and incorporate distribution costs, billing costs, and losses. Relative to many other areas of the world, rates for consumers in the Caribbean are high. The high rates result from limitations on indigenous fuel resources, the expense of operating diesel plants, high losses, and costly

distribution requirements. The high rates for electricity suggest that, all else equal, renewable technologies should be more economically viable in this region. (For example, the project modelling analysis in Chapter 3 demonstrates that wind power can be profitably developed at 4-6 cents per KWH). All else being equal, the countries with the highest rates should present the most beneficial opportunities for renewable resources. A graph of rates in a country can be effective in accompanying a background presentation by developers as part of an information memorandum.

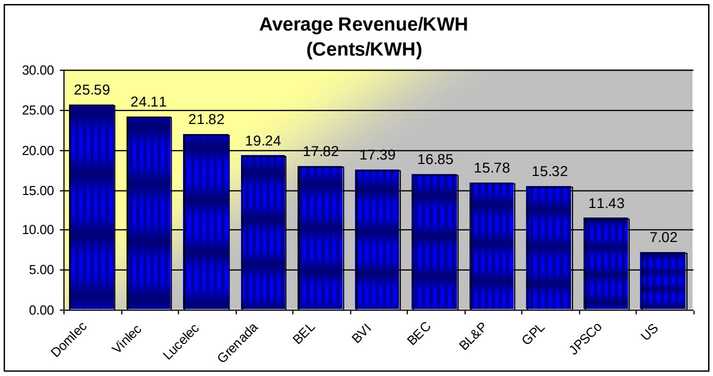


Figure 69 - Average Revenue

The most significant output of the rate impact analysis is the rate level of the utility company. As explained in the section below, the future rate level is computed by assuming that the return on capital meets pre-determined criteria. This means that in future years, utility companies in the region have their rates adjusted to meet the same rate of return. The graph shows historic and projected prices for Domlec in the three different oil price scenarios developed by the U.S. Energy Information Administration. Key drivers of rate changes are the world price of oil and capital expenditures required to meet load growth. Both of these drivers of future rate increases can be mitigated with renewable resources.

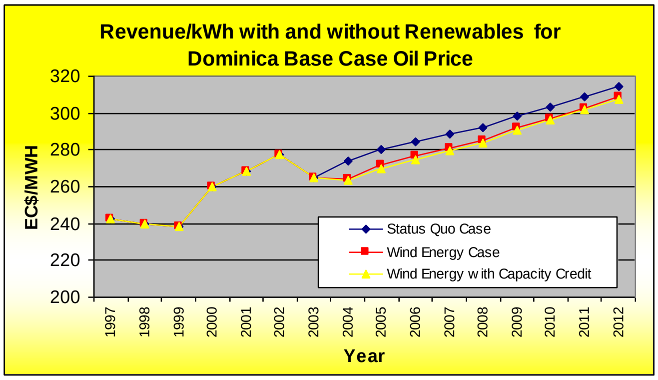


Figure 70 - Domlec Average Revenue

Avoided Fuel and Variable O&M Cost

The third graph compares the average fossil fuel cost per MWH of generation across utility companies. We present this graph because it is a rough proxy for the avoided fuel cost of utility companies. (It is not a proxy for avoided energy cost because it does not include variable O&M cost, avoided capacity costs, or losses). Fuel cost per MWH depends to a significant extent on the price of oil. Therefore, the analysis of renewable projects cannot be derived from a simple snapshot of fuel costs. However, this graph is important in demonstrating the economic benefits of RET because the required PPA prices computed in Chapter 3 are generally below these fuel prices.

To illustrate how average fuel expense can approximate avoided fuel cost, consider a utility company that uses diesel plants to produce virtually all of its power and whose different diesel plants all have similar fuel cost per MWH because they have similar heat rates. In this case the avoided fuel cost will be approximately the same as the total fuel expense divided by the fossil energy generation, since the change in fuel expense, given a change in load, can be measured by the average fuel cost per MWH. For many utility companies in CARICOM, a collection of similar plants is representative of the power plant portfolio implying that average fuel cost is a good representation of avoided cost. For example, John W. Whittingham noted that on the island of Grand Turk, there is one generating station that has three 1,000 kW Caterpillar 3516 diesel engine generator sets. Peak demand is currently 1,400 kW and the minimum demand is about 750 kW.[31]

In cases where utility companies have different types of plants (e.g. steam, hydro and diesel plants) and where companies use economic dispatch, the avoided cost will generally be higher than the average cost. In cases with a portfolio of different plants that have different heat rates, the avoided cost is the most expensive unit to dispatch, while the average cost includes units that have lower fuel cost whose operation is not affected by deployment of different resources such as renewable technologies. This issue is addressed in detail as part of the avoided cost analysis in Chapter 4.

The graph shows that average fuel cost varied between $80/MWH for Domlec and $40/MWH for JPSCo. As we receive data from the detailed utility company survey, we will complete the more detailed avoided cost analysis. This analysis accounts for variation in hourly loads, specific heat rate information on the plants, measurement of avoided cost by time period, inclusion of problems that can occur if RET causes diesel plants to operate at minimum levels and other issues. The avoided cost analysis also addresses the question of avoided capacity costs of renewable technologies, which we measure by analysing loss of load probability. Two companies provided actual prices used in PPA contracts. PPA prices in Belize were$57.5/MWH, and in Jamaica the price was $55/MWH. An earlier PPA in Jamaica for the Rockfort plant had a higher PPA price of about $61/MWH.

[31] Case Studies In The Caribbean, Wind Energy System in the Caribbean

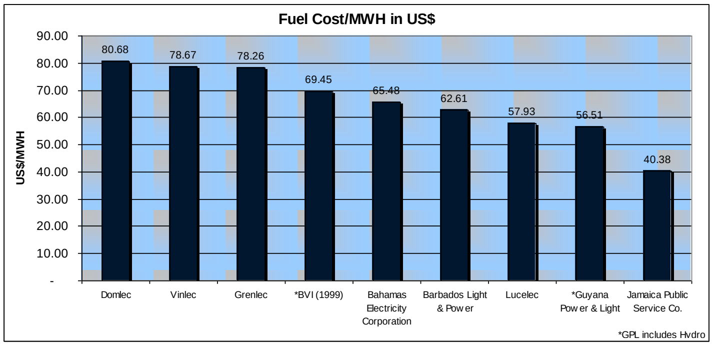


Figure 71 - Average Fuel Cost

The next group of charts compares fuel cost per MWH across utility companies demonstrates the fuel costs of each utility company during a single year. This graph can be a misleading representation of avoided fuel cost since oil prices in the year 2000 were relatively high. The next set of graphs illustrates how fuel costs for various islands track the world price of oil. The world price of oil is the price to refineries in the Gulf of Mexico as reported by the EIA. (We have investigated the Caribbean posted price, but could not obtain data). The graphs below demonstrate that the avoided cost is highly dependent on assumptions with respect to future fuel prices.

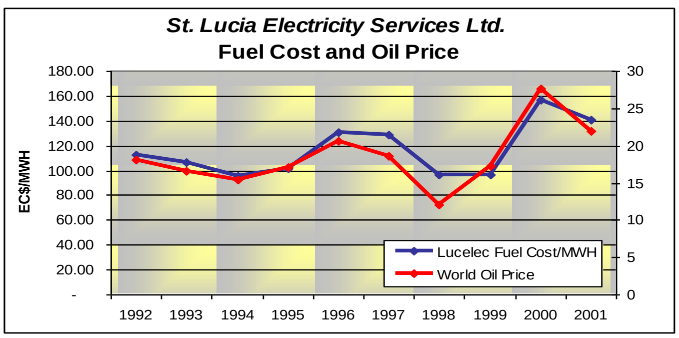


Figure 72 - Fuel Costs for Lucelec vs. World Prices

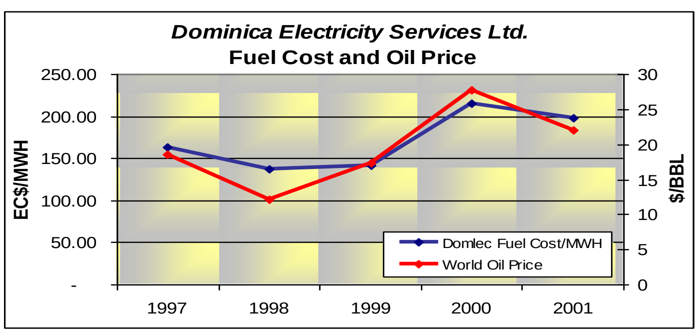


Figure 73 - Dominica Fuel Cost and Oil Price

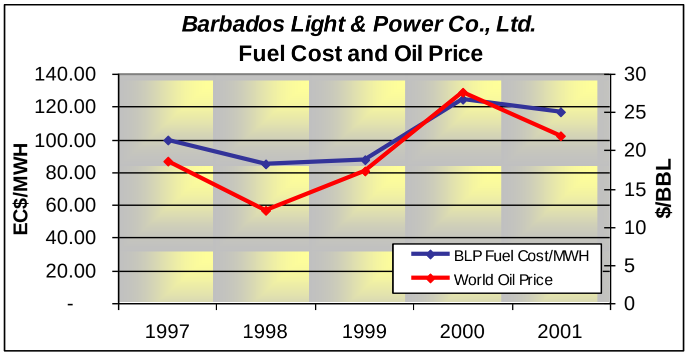


Figure 74 - BL&P Fuel Cost and Oil Price

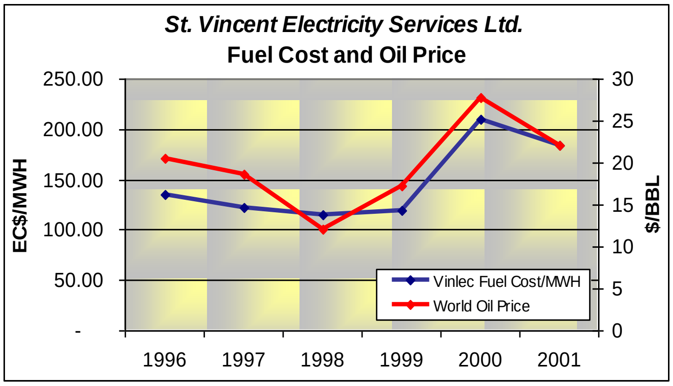


Figure 75 - Vinlec Fuel Cost and Oil Price

Avoided costs from deployment of renewable resources include the reduced costs of operating and maintaining generating capacity, as well as the reduced cost of fuel losses and avoided capacity costs. Diesel plants are maintenance intensive with high variable operation and maintenance costs as compared to other conventional power plants. If energy from renewable energy projects reduces the energy produced from diesel plants, the variable O&M expenses incurred by utility companies will also be reduced.

Unfortunately, the variable O&M expense cannot be measured from financial statements because total operating expenses are presented on the income statement where the total does not distinguish between variable and fixed positions. However, the total non-fuel generation cost should give some indication of the cost even though it includes fixed and variable expenses. In the rate impact analysis, we assume 50% of the non-generation costs are variable. The total non-fuel generation cost can then be divided by total generation to give an indication of the cost of operating units.

Many companies in the region do present the total generation operation and maintenance expense in their financial statements. For example, Domlec reports total operating cost other than fuel of $___. This amount is categorized into generation costs, distribution costs, billing costs and ___. We have allocated the administrative costs to generation costs. The following graph illustrates the range of total operation and maintenance divided by the amount of MWH generation. The graph shows estimated variable O&M

cost per MWH in the region. The variable O&M per MWH ranges from $74/MWH for Guyana Power & Light to $20/MWH for JPSCo.

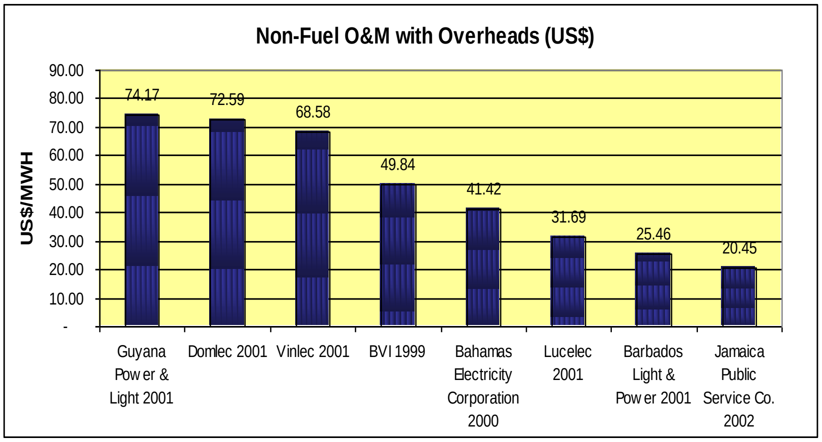


Figure 76 - O&M Cost per MWH

Reserve Margin

Renewable technologies allow a company to avoid capital expenditures (and fixed O&M) for new capacity, as well as fuel and variable O&M. The value of capacity reduction from development of renewables ranges from more than 100% for geothermal plants to 20% for wind farms. Capacity credits or avoided capacity costs occur when renewable energy is being produced during the peak hour of a year. For example, a geothermal plant expected to operate at a 90% capacity factor will probably be producing electricity at peak load hours, implying that other capacity can be reduced. In this case, the firm capacity credit should be 100%. In other cases, such as hydro plants, the water flows vary, and one cannot rely on the entire generation potential of the plant because there may not be enough water flow. In these cases, the firm capacity or the capacity credit is determined by low water years.

For wind projects, it may be typical that that the wind turbines are operating during peak load hours. Say the peak occurs at 3:00 PM on a weekday in February. If the wind project is typically running at 50% of its rated capacity on this hour, the capacity credit may be 50% of the capacity of the project depending on the stochastic nature of wind. In this case, the capacity credit of the wind turbine should be half the installed capacity of the equipment. On the other hand, if the wind turbine is virtually never producing during the peak load hour the capacity credit should be nothing.

The value of capacity credits for renewable technologies depends on the amount of new capacity that is added. In both the rate impact analysis and the avoided cost analysis, the reserve margin drives the amount of new capacity additions. The reserve margin is presented on the graph below to provide background on capacity credits for different companies in the region. The reserve margin is computed as the capacity minus the peak load divided by the firm capacity. If the reserve margin is low, the country needs capacity and the capacity credit from renewable energy can be significant. The graph illustrates

that the reserve margin varies between 53.35% for Lucelec and 24.62% for Domlec. It is important to note that reserve margins do not tell the whole story, especially for small systems. For example, Lucelec may have a high reserve margin representative of the size of the next addition.

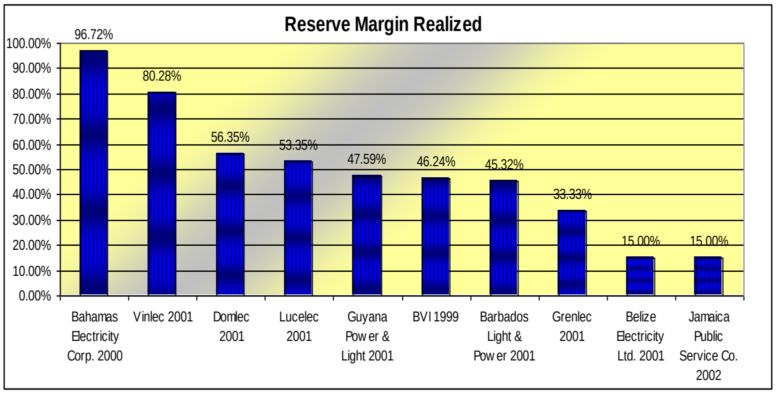


Figure 77 - Reserve Margin

Financial Condition of Caribbean Utility Companies

The rate impact analysis uses a financial model in which projections of revenues, expenses and capital expenditures are used to forecast financial statements. The financial analysis can be used to evaluate the financial viability of companies in the region. The assessment of financial condition can be important in practical implementation of renewable technologies. If the utility itself is developing a project, it must have the financial capability to make the investment.

The financial viability of utility companies has been suggested as an impediment to renewable development. Gerald Huttrer stated that geothermal plant development has been constrained because of weak financial condition of utility companies (see Binder #16). Note that we do not agree with this reason for problems with geothermal development. Actual development is in fact more related to up-front resource assessment, and no project has reached the financing stage.

The financial condition has two effects on renewable development. First, as stated in the introduction, utility companies may be the developers of renewable technologies. In this case, when a company has a relatively weak financial condition, it will have difficulty in financing capital intensive plants. Second, the financial condition of utility companies is an important part of the banking analysis in project financing. It will be more difficult to arrange private financing in cases where the off-taker utility company is in a weak financial condition.

The graph of interest coverage for each utility company in the region is presented to illustrate the relative financial position of companies in the region to support PPA contracts or capital expenditures for renewable projects. Interest coverage measures the

level of earnings relative to interest expense. A ratio of 1.0 means that earnings only cover interest. All else equal, companies with interest coverage ratios below 2.2 are having financial difficulty – Standard and Poor's publishes benchmarks for utility companies and those with ratios below 2.0 have a benchmark below investment grade.

The graph shows that interest coverage ranges between 6.24 for Grenlec and 1.34 for Domlec. This suggests that a PPA between a developer and Domlec would more likely need government guarantees than other companies.

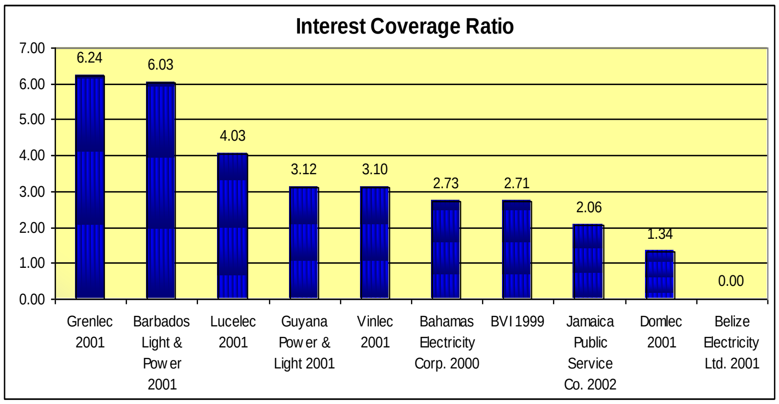


Figure 78 - Interest Coverage Ratio

The credit quality of a company is determined by the debt to capital ratio as well as the interest coverage ratio. This measures the ability of utility companies to finance renewable projects or to support PPA contracts as off-takers. In other words, the debt to capital ratio is also important in supporting PPA agreements. Just as there are ratios that define benchmarks for utility companies in terms of the interest coverage ratio, there are ratios for debt to capital. The graph below illustrates that debt to capital ratios vary between 54% for British Virgin Islands and 12% for Barbados Light & Power.

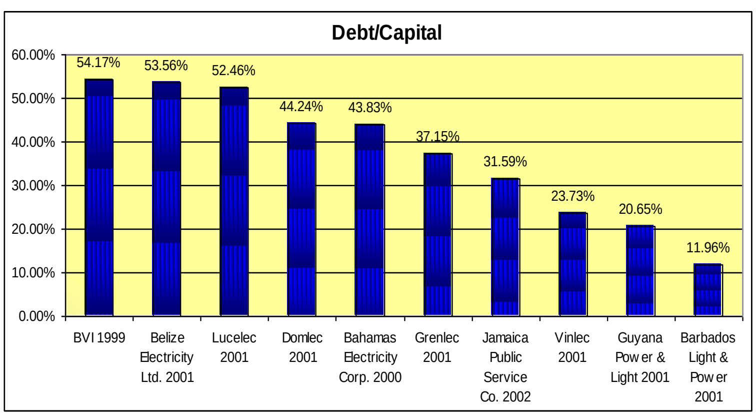


Figure 79 - Debt to Capital Ratio

The graph of return on invested capital is intended to further illustrate the financial position of utility companies in the region. This graph is also presented because return on

investment is the basis for assumed rate increases in the rate impact analysis. For each company, the return on investment is adjusted to a constant level in every year when constructing the rate projections. The graph illustrates a range in return on invested capital from 29% for Domlec to 1.5% for Guyana Power & Light.

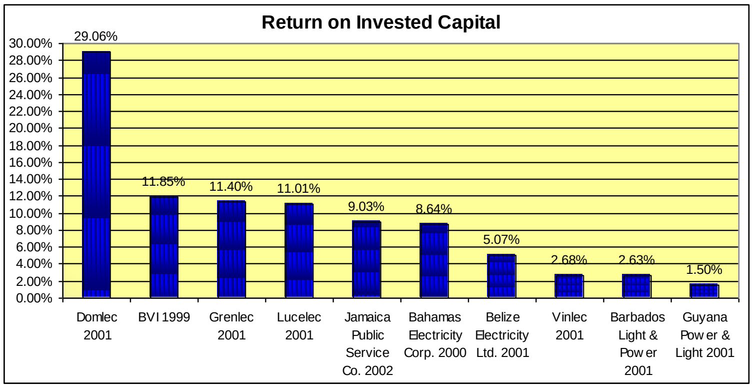


Figure 80 - Return on Invested Capital

Losses

The annual reports of most companies show statistics on losses. Losses are an important component for off-grid projects where, since the projects are behind the meter, the losses of a company are reduced. The CARICOM pipeline currently includes three off-grid solar projects. Eventually, the number of off-grid projects could be increased significantly for programs such as solar water heaters for hotels. The appropriate financial model to evaluate the viability for off-grid projects should use a cash flow model that computes payback periods. The accompanying graph shows that losses range from 43% in the case of Guyana to 11% for St. Vincent.

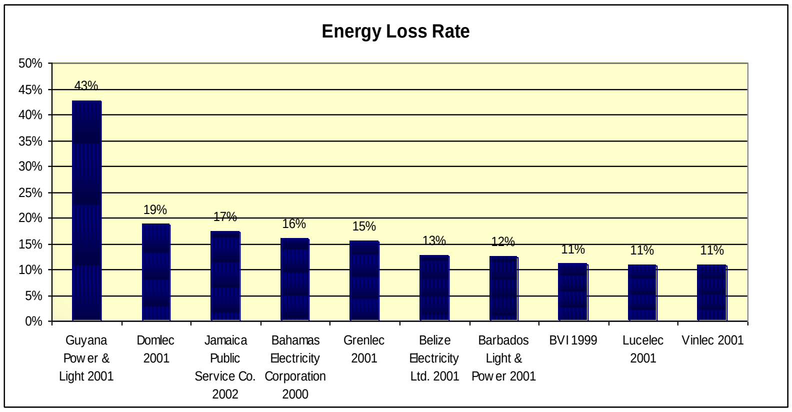


Figure 81 - Energy Loss Rate

Section 3: Analytical Approach of the Rate Impact Model

The rate impact analysis is founded on a financial model that combines financial data on the utility company with capacity, load, sales, and generation data. Forecasts depend on assumed load growth, fuel costs, capacity expansion, cost of new capacity, and other factors. The financial model is an annual model with a relatively simple production cost and capacity addition routine. The model assumes that if renewable resources are not developed, required capacity to meet a reserve margin target will be met through diesel capacity. More comprehensive production cost and simulation resources are incorporated in the avoided cost model.

From an energy perspective, the diesel capacity is assumed to be the "swing" energy production. This means that if added or reduced energy is required, the change occurs in diesel generation. This process is illustrated with the following simple equations:

Generation requirements = load growth x (1+loss rate)

Generation from diesel = total generation - generation from other sources

Dollar cost of diesel fuel = cost/MWH (as a function of oil price) x Diesel generation

From a capacity perspective, new diesel capacity is assumed to be the default type of generation addition in the status quo case. The amount of new capacity is driven by the assumed reserve margin. The capacity increase is illustrated by the following equations:

Capacity requirement = peak load x (1 + reserve margin)

New capacity = capacity requirement – existing capacity (adjusted for retirements)

Dollar capital additions = New capacity x (cost/kW of new diesel capacity)

The new capacity additions can be adjusted for specific plans in place from the utility company. We have requested these additions as part of the utility survey.

Implicit Avoided Cost Calculation in the Rate Impact Analysis

In computing the effect on rates from adding renewable resources, the energy produced by the RET project is simulated, and the energy produced by conventional fossil resources is reduced. When the fossil resources are reduced, the cost is also reduced. The reduction in costs that results from production of RET energy involves an implicit calculation of avoided costs.

The avoided costs in the rate impact analysis are derived from public data reported in the annual reports. It does not reflect the operation of different types of plants and the potential effects of variations in hourly loads over the year. We note that use of average fuel expense per MWH may understate avoided cost and the benefit of renewable

resources. The following quote from Whittington illustrates that seasonal analysis may be important in quantifying the benefits of renewable resources:

> "A peculiarity of the Caribbean climate is that the wind blows hardest in the dry season, which is also the tourist season, falling off somewhat in the wet season. In those countries with hydroelectric resources, which are all run of river, wind and hydro generation would complement each other, with the potential to result in a relatively stable output of power from renewable sources during the course of a year."

Issues associated with the seasonal operation of renewable resources are addressed in Chapter 4.

Section 4: Data and Assumptions in the Rate Impact Analysis

This section describes the key data and assumptions for the rate impact analysis. The data for the rate impact analysis are derived from annual reports, oil prices from the EIA, and renewable resources parameters from the project modelling report (Chapter 3).

Cost of New Diesel Capacity

The rate impact model has an implicit avoided cost capacity cost calculation. When a technology such as geothermal is added in the model, less diesel capacity must be added. Since diesel capacity is the default addition, the avoided capacity cost is driven by the cost of constructing diesel capacity.

To establish the cost of new diesel capacity, we have used researched different sources. For example, the Jamaica Rockfort slow speed diesel plant has a capacity of 60MW. In 1994 the plant cost was $89.33 million for the EPC, $21.91 million for financial costs -- $11.96 million of which was interest during construction ("IDC"), and the remainder was fees and insurance. Development costs were $15.58 million or 17% of the EPC cost. Total costs were $126.82 million or $2,114/KW[32]. By contrast, a study of the Jamaican system using WASP assumed a cost of $1150/KW for a medium speed plant, and $1600/KW for a slow speed plant. According to the survey from the Bahamas, the cost of new diesel capacity ranges from between $800/KW and $1200/KW.

Antigua stated that the cost of new capacity is $900/KW. The cost/KW of diesel plants in Latin America has varied between $400/KW and $1,400/KW as shown in the table below. In the rate impact model, we assume a capital cost of $900/KW.

[32] Financing Jamaica's Rockfort Independent Power Project, RMC Discussion Paper Series 121.

Table 39 - Cost of New Diesel Capacity

Country	Parent Company	Project Name/ Region	Commercial Operation or Acquisition Date	MW	Fuel Type	Project Cost USD MM	Cost per KW
Dominican Republic	Maxon Corp.	Boca Chica Power Barge	2000	105	Diesel	$ 40.0	$ 380.95
Dominican Republic	Odyssea Vessels Inc.	Cayman Power Barge Ltd.	1998	50	Diesel	$ 20.0	$ 400.00
Dominican Republic	Compania Electricidad de Punta Cana Macao	Consorcio Energetico Punta Cana	1994	12.5	Diesel	$ 12.5	$1,000.00
Guatemala	Centrans Energy Services; Commonwealth Devt Corp; Enron Corp	Esperanza Power Barge	2000	124	Diesel	$ 50.0	$ 403.23
Guatemala	Siderurgica de Guatemala	Escultina power plant	1996	40	Diesel	$ 40.0	$1,000.00
Guatemala	Consolidated Edison Development; Interamerican Power and Light Corp; Intl Energy Partners	Generadora Electrica del Norte	1997	40	Diesel	$ 21.6	$ 540.00
Mexico	Alstom; Sithe Energies Inc	Temoelectrica del Golfo	2000	460	Diesel	$ 608.7	$1,323.26
							$ 721.06

Load Growth

Growth in peak demand and electric energy sales can have important impacts on the economics of renewable resources. If, for example, load is declining, the renewable resources cannot have capacity credit and avoided costs may decline. Load growth also drives the requirements of utility companies to finance capital expenditures – if financing requirements are high, renewable resources can be favourable.

Fuel Price Forecasts

To compute fuel prices, we have researched oil price forecasts from alternative sources, and we have analysed the relationship between historic fuel expense per MWH for each utility company and the world oil price. As demonstrated in the previous section, for all systems in the Caribbean, the price of oil has a major influence on avoided cost. Alternative fuel price forecasts tabulated by the U.S. Energy Information Administration (EIA) are shown in the table below:

Table 40 - Alternative Fuel Price Forecasts

Table 15. Comparison of World Oil Price Projections, 2005-2025
(2001 Dollars per Barrel)

Forecast	2005	2010	2015	2020	2025
IEO2003					
Reference Case	23.27	23.99	24.72	25.48	26.57
High Price Case	28.65	32.51	32.95	33.02	33.05
Low Price Case	22.04	19.04	19.04	19.04	19.04
Altos	22.64	23.40	25.58	27.90	31.61
GII	20.80	21.70	23.76	25.39	—
IEA	21.47	21.47	23.52	25.56	27.61
PEL	21.21	18.46	17.47	—	—
PIRA	22.43	23.33	26.32	—	—
NRCan	22.28	22.28	22.28	22.28	—
DBAB	19.04	18.94	19.34	19.07	19.18
EEA	20.98	20.47	19.98	19.50	—

We have decided to use the World Oil Price forecast published by the U.S. Energy Information Administration in the analysis. We have used this forecast after consulting with other energy experts who explained that this is the most commonly used forecast, and it includes high and low case projections. The forecast of oil prices in the EIA are presented in real US$, while the rate analysis is in nominal terms. The reason project modelling and rate modelling is in nominal terms is due to the manner in which financial

data is presented and because interest rates are in nominal terms because the forecasts use a financial model. The reason project modelling and rate modelling is in nominal terms is due to the fact that financial data is recorded in nominal terms, and because interest rates are in nominal terms. Therefore, we converted the real US$ to nominal US$ using the inflation projections presented in the EIA forecasts.

The EIA forecasts can be found at the following websites:
http://www.eia.doe.gov/oiaf/aeo/results.html :
http://www.eia.doe.gov/oiaf/aeo/pdf/aeo_base.pdf - Reference Case Prices
http://www.eia.doe.gov/oiaf/aeo/pdf/aeo_hw.pdf - High Case Prices
http://www.eia.doe.gov/oiaf/aeo/pdf/aeo_lw.pdf - Low Case Prices

The oil price forecasts and the historic oil prices are shown in the graph below.

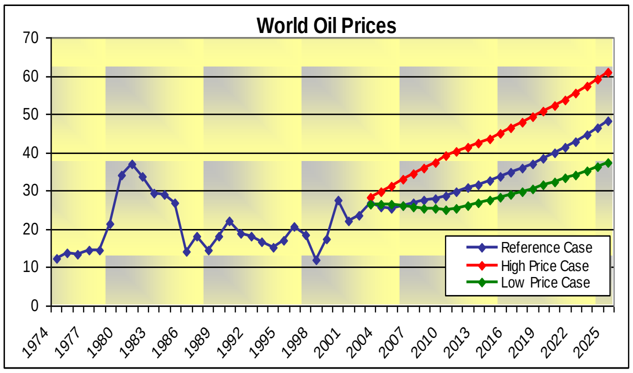


Figure 82 - World Oil Prices

Detailed sources that explain the fuel price forecasts, including the EIA, are documented in Binders 13 and 14.

Variable O&M

Variable operation and maintenance expenses are an important component of avoided costs for countries in the Caribbean because of the maintenance intensive nature of diesel plants. However, obtaining data on actual variable O&M costs for individual plants is a difficult process. We have estimated variable O&M assumptions using two approaches – use of industry experts and use of financial data. In the first method, we have attempted to find information on typical O&M expense costs of diesel plants through contacting diesel suppliers and industry experts (see text box)[33]. This research suggests that diesel operation and maintenance expenses should be at least $10-$15/MWH for high speed peaking plants. The variable cost/MWH for the Rockfort slow speed diesel plant was estimated to be $5.2/MWH in a write-up on the project. In the second method, we have computed actual non-fuel operation and maintenance expenses from historic data in the annual reports of utility companies. However, the data reported by utility companies does

[33] We have requested variable O&M costs from utility companies in the survey; however, the utilities were not able to provide data.

not distinguish between fixed and variable costs. Therefore, we have assumed that 50% of non-fuel generation costs are variable. We have also included administrative costs and overheads in the calculation. Most companies report non-fuel operation and maintenance costs and also show the expenses for generation as opposed to distribution. The avoided costs for each utility system presented in Volume II use the second method.

Variable O&M on High Speed Diesel Plants

In describing the cost of maintaining diesel plants, we interviewed a representative of Caterpillar. Mr. Garelos read from a maintenance manual on diesel operations. He explained that the variable O&M on diesels is at minimum between 1.0 and 1.5 cents/KWH ($10/MWH to $15/MWH). He stated that over the life of a diesel generator, there should be five major overhauls. Maintenance activities that are driven by operation of the plant – variable maintenance -- include:

1. Change oil every 500 hours {at 60% load factor, this means one must change the oil 29 times per year};
2. At 1,000 hours, change secondary fuel filter {at 60% load factor, change the secondary filter 14 times per year -- a little more than once per month};
3. At 6,000 hours, complete a number of inspections {about once a year};
4. At 7,500 to 11,000 hours, one must complete a top end overhaul;
5. At 22,500 to 33,000 hours, one must complete a major overhaul {this occurs about once every two years which means if the machine will last for 10 years with 5 overhauls}. Mr. Garelos stated that the O&M costs are a function of fuel use and load factor -- not time which means they are variable costs. If the overhauls are not done at the prescribed hours, he stated that the warranty is void.

Exchange Rates

In order to make analysis comparable for the different countries, all currencies are translated to US$ when we present summary results. However, since the financial data in the annual reports is presented in local currency, the detailed modelling is developed in local currency. The historic financial data, the cost of fuel and operation and maintenance, as well as assumed costs of new diesel expenditures are all converted from the currency used in the annual reports to US$ using exchange rates in the table below. Exchange rate information is included in Binder 1 - General Caribbean Information. All currencies except for Guyana, Jamaica, and Trinidad are tied to the U.S. dollar. For the countries with floating exchange rates, we assume constant exchange rates over the forecast horizon and inflation rates that correspond to the U.S. dollar.

Table 41 - Currency Conversion

National Currency per United States Dollar - (US$)

COUNTRY	NATIONAL CURRENCY	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
THE BAHAMAS	Bahamas Dollar - B$	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
BARBADOS	Barbados dollar - Bd$	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000
BELIZE	Belize dollar - BZ$	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000
GUYANA	Guyana Dollar - G$	2.5500	2.7860	3.0030	3.0030	3.8610	4.2900	4.2900	9.6530	10.0100	20.9510	48.2630
JAMAICA	Jamaica Dollar - J$	1.7800	1.7800	1.7800	1.9300	3.9400	5.5600	5.4800	5.4900	5.4900	5.7500	7.1800
SURINAME	Suriname Guilder - Sf	1.7850	1.7850	1.7850	1.7850	1.7850	1.7850	1.7850	1.7850	1.7850	1.7850	1.7850
TRINIDAD & TOBAGO	Trinidad & Tobago - TT$	2.4000	2.4000	2.4000	2.4000	2.4000	2.4500	3.6000	3.6000	3.8400	4.2500	4.2500
	EC$	2.7000	2.7000	2.7000	2.7000	2.7000	2.7000	2.7000	2.7000	2.7000	2.7000	2.7000

COUNTRY	NATIONAL CURRENCY	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
THE BAHAMAS	Bahamas Dollar - B$	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
BARBADOS	Barbados dollar - Bd$	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000
BELIZE	Belize dollar - BZ$	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000
GUYANA	Guyana Dollar - G$	118.5400	124.9500	126.8500	138.8900	141.8500	140.0500	141.9300	150.4600	177.0700	181.0100	187.1100	190.6267
JAMAICA	Jamaica Dollar - J$	12.7600	22.8900	25.5800	33.1600	35.3500	36.8800	35.4800	36.5200	39.1800	43.1900	46.0988	48.0725
SURINAME	Suriname Guilder - Sf	1.7850	1.7850	74.1200	201.0500	412.0000	406.0000	406.0000	406.0000	995.0000	1339.2000	2200.0000	2540.0000
TRINIDAD & TOBAGO	Trinidad & Tobago - TT$	4.2500	4.2500	5.3400	5.8700	5.8900	5.9900	6.2500	6.2800	6.2700	6.2750	6.1997	6.2109
	EC$	2.7000	2.7000	2.7000	2.7000	2.7000	2.7000	2.7000	2.7000	2.7000	2.7000	2.7000	2.7000

Renewable Resource Parameters

Renewable resource parameters include the amount of renewable capacity, the capacity factor of renewable resources, and the amount of the renewable resource that can be classified as firm capacity. We have used the pipeline as an indication of the amounts of capacity. The renewable resource parameters are discussed in detail in the project modelling chapter.

Section 4: Mechanics of the Rate Impact Model

This section describes how the rate impact model operates. We first describe the capacity and load analysis, and the energy source and disposition analysis. Next, we discuss computation of capital expenditures, revenues, and expenses. For illustrative purposes, we use Dominica as a case study.

The model begins by establishing a forecast load growth. The average load growth Dominica was 5.39% from 1998-2001. Using installed capacity for diesel and firm for hydro, the reserve margin was 24.6% in 2001 (this reserve margin is low relative to other islands). In the future, we assume the required reserve margin is 25%. Due to load growth and assumed plant retirements, the new capacity accumulates to almost 40MW over the forecast horizon as shown in the table below. The lines for planned new capacity are used if information is provided by the utility company. Retirements are either provided by the utility company as part of the survey or estimated from the existing portfolio of plants.

Data from the historic analysis allows us to make reasonable assumptions for peak load growth and sales growth. For example, in the case of Lucelec, average peak load growth has been 6.65% from 1992 through 2001. Peak load growth has been more than 10% in 1992, 1993, and 1999. These high growth rates and assumed improvements in tourism are used to create a high load growth case of 9%. Similarly, the loss assumptions, the reserve margin assumptions, the fuel cost assumptions, the non-generation assumptions, the financing assumptions, and the cost of new capacity can all be derived from analysis of historic data in the rate impact analysis.

The load and capacity report is illustrated in the table below:

Table 42 - Load and Capacity Report

			2002									
	Units	Formula	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Capacity and Peak Load												
Total Peak Load	kW	Input/Growth	11,390	12,348	13,010	12,966	13,866	14,823	15,795	16,647	17,544	18,490
Existing Capacity Retired												
Hydro	kW	Assumed			-	-	-	-	-	-	-	-
Diesel	kW	Assumed			-	-	-	-	-	3,000.00	-	-
Other	kW	Assumed			-	-	-	-	-	-	-	-
Existing Owned Capacity												
Hydro	kW	Prior - Retired	2,130	2,130	2,130	3,200	3,200	3,200	3,200	3,200	3,200	3,200
Diesel	kW	Prior - Retired	10,036	11,090	11,090	12,840	14,080	14,080	14,080	11,080	11,080	11,080
Other	kW	Prior - Retired	-	-	-	-	-	-	-	-	-	-
Total Existing		sum	12,166	13,220	13,220	16,040	17,280	17,280	17,280	14,280	14,280	14,280
New Capacity Planned												
Constructed Diesel Capacity	kW	Input			-	-	-	-	-	-	-	-
Contracted	kW	Input			-	-	-	-	-	-	-	-
Renwable Credit	kW	Input	-	-	-	-	-	-	-	-	-	-
Total Planned			-	-	-	-	-	-	-	-	-	-
Subtotal Capacity	kW	Sum	12,166	13,220	13,220	16,040	17,280	17,280	17,280	14,280	14,280	14,280
New Assumed Capacity to Meet Reserve Mgn	kW							1,248	2,464	6,528	7,650	8,833
Total Capacity	kW	Sum	12,166	13,220	13,220	16,040	17,280	18,528	19,744	20,808	21,930	23,113
Reserve Margin Realized	pct	Capacity/Peak-1	6.81%	7.06%	1.61%	23.71%	24.62%	25.00%	25.00%	25.00%	25.00%	25.00%
Total Diesel Capacity	kW	Existing + New	10,036	11,090	11,090	12,840	14,080	15,328	16,544	17,608	18,730	19,913

Energy source and disposition is shown in the table below. In this table the sum of sales and losses equate to the energy generation requirements.

Table 43 - Energy Source and Disposition

	Units	1997	1998	1999	2000	2001	2002	2003	2004	2005
Requirements and Sources of Energy										
Energy Loss Rate	Loss/Gen	21%	19%	19%	20%	21%	20%	20%	20%	20%
Hydro Capacity Factor	Pct	181%	181%	180%	174%	113%	96%	149%	149%	149%
Renewable Capacity Factor		33%	33%	33%	33%	33%	33%	33%	33%	33%
Energy Requirements										
Electricity Sold										
Residential Customers	MWH	26,721	28,716	30,023	30,872	31,779	33,972	36,200	38,152	40,209
Commercial Customers	MWH	13,435	14,767	15,503	16,052	17,021	18,195	19,389	20,435	21,536
Industrial Customers	MWH	12,137	13,811	15,068	15,081	15,114	16,157	17,217	18,145	19,123
Total Sales	MWH	52,293	57,294	60,594	62,005	63,914	68,324	72,806	76,732	80,869
Add: Losses	MWH	13,490	13,006	14,042	15,510	17,051	16,845	17,950	18,918	19,938
Other Energy Requirements										
Total Energy Requirements		65,783	70,300	74,636	77,515	80,965	85,169	90,756	95,649	100,807
Energy Sources										
Purchases from IPP's										
Purchases from Renewable Sources		-	-	-	-	-	-	-	-	-
Energy Generation										
Hyrdo	MWH	33,841	33,670	32,410	31,590	27,036	27,036	41,748	41,748	41,748
Other	MWH	-	-	-	-	-	-	-	-	-
Sub-Total Energy Soruces before Diesel		33,841	33,670	32,410	31,590	27,036	27,036	41,748	41,748	41,748
Required Diesel Generation	MWH	31,942	36,630	42,226	45,925	53,929	58,133	49,007	53,901	59,058
Total Energy Sources	MWH	65,783	70,300	74,636	77,515	80,965	85,169	90,756	95,649	100,807
Resulting Diesel Capacity Factor	Pct	36.3%	37.7%	43.5%	40.8%	43.7%	43.3%	33.8%	34.9%	36.0%

The second step in the analysis is computing the required diesel generation from the sales growth and the loss rates. The required generation is established from computing the energy source and disposition table that is typical in developing financial models of utility companies.

Given the level of sales, peak load, new capacity, losses, and generation from various sources, then the capital expenditures, revenues, and expenses can be compiled. The capital expenditures are computed from adding expenditures for the cost of new capacity with the cost of non-generating expenditures. The non-generating expenditures are derived from historic analysis of expenditures, while new capital is calculated from the cost of new capacity multiplied by the amount of new capacity.

Total Capital Expenditure = New Capital for Capacity Additions + Existing Capital Expenditures

Where:
*Existing Capital Expenditures = Trend from historic and New Capital Expenditure = New Capital * Cost of Capacity*

Table 44 - Capital Expenditures

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Capital Expenditures										
Inflation Index	1.00	1.00	1.00	1.00	1.00	1.02	1.04	1.06	1.08	1.10
New Generation Capital Expenditures										
New Diesel Capacity Added (kW)	-	-	-	-	-	1,248	1,215	4,065	1,122	1,182
Real Cost per kW of New Capacity	$ -	$ -	$ -	$ -	$ -	$ 900.00	$ 900.00	$ 900.00	$ 900.00	$ 900.00
Exchange Rate	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70
Nominal Cost per kW of New Capaacity	$ -	$ -	$ -	$ -	$ -	$ 2,478.60	$ 2,528.17	$ 2,578.74	$ 2,630.31	$ 2,682.92
Capital Cost of New Capacity	-	-	-	-	-	3,094	3,073	10,482	2,951	3,173
Non- New Generation Capital Expenditures	-	10,597	3,811	10,599	10,262	11,189	12,162	13,074	14,055	15,109
Total Capital Expenditures	-	10,597	3,811	10,599	10,262	14,284	15,235	23,556	17,006	18,281

The first historic year in the analysis depends on the data provided in the annual reports. The analysis is in local currency because of the format of data in the annual reports.

The operating expenses are computed for fuel expense, variable O&M expense as a function of diesel generation, for capacity on the basis of the amount of capacity and for non-fuel generation which is trended from historic data.

Total Expenses = Fuel Expense + Variable O&M + Fixed O&M + PPA Costs + Other

Where:

*Fuel Expense = Trended Cost/MWH * Diesel Generation (MWH)*

*Variable O&M = Variable O&M Cost * Generation (MWH)*

*Fixed O&M = Fixed O&M/KW * Capacity (KW)*

*PPA Cost = PPA Price * Renewable Energy (MWH)*

In renewable cases, the PPA costs are taken from project modeling. The mechanics of computing total operating expenses in this manner are illustrated on the table below:

Table 45 - Computing Total Operating Expenses

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Operating Expenses										
General Inflation Index	1.00	1.00	1.00	1.00	1.00	1.02	1.04	1.06	1.08	1.10
PPA Price for Renewable Energy	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00
Fuel Cost										
Diesel Generation	31,942	36,630	42,226	45,925	53,929	58,133	49,007	53,901	59,058	64,494
Real Cost per MWH	163.36	137.65	141.78	215.42	198.00	198.00	198.00	198.00	198.00	198.00
Fuel Price Index	1.00	1.00	1.00	1.00	1.00	1.07	1.22	1.17	1.16	1.19
NominalCost per MWH	163.36	137.65	141.78	215.42	198.00	212.54	242.32	231.36	228.84	235.04
Total Fuel Cost	5,218	5,042	5,987	9,893	10,678	12,356	11,875	12,471	13,515	15,158
PPA Contract Cost										
PPA Energy	-	-	-	-	-	-	-	-	-	-
PPA Cost	-	-	-	-	-	-	-	-	-	-
Variable Operation and Maintenance Cost										
Real Cost/kWh of Variable O&M	61.78	69.36	65.99	72.79	98.09	82.45	82.45	82.45	82.45	82.45
Nominal Cost/kWh of Variable O&M	61.78	69.36	65.99	72.79	98.09	84.10	85.78	87.50	89.25	91.03
Total Variable Operation and Maintenance	1,973	2,541	2,786	3,343	5,290	4,889	4,204	4,716	5,271	5,871
Fixed Operation and Maintenance										
Real Fixed O&M/kW for Generation	164.03	189.53	196.67	241.07	307.65	307.65	307.65	307.65	307.65	307.65
Nominal Fixed O&M/kW for Generation	164.03	189.53	196.67	241.07	307.65	313.80	320.07	326.48	333.01	339.67
Total Capacity	12,166	13,220	13,220	16,040	17,280	18,528	19,744	20,808	21,930	23,113
Total Fixed Operation and Maintenance	1,996	2,506	2,600	3,867	5,316	5,814	6,320	6,793	7,303	7,851
Fuel, Variable Generation O&M and Fixed O&M	9,187	10,088	11,373	17,103	21,284	23,059	22,399	23,980	26,088	28,880
Total Operation and Maintenance	20,587	22,730	23,681	30,629	36,745					
Other Operation and Maintenance - Real	11,400	12,642	12,308	13,526	15,461	15,461	15,461	15,461	15,461	15,461
Other Operation and Maintenance - Nominal	11,400	12,642	12,308	13,526	15,461	15,770	16,085	16,407	16,735	17,070
Total O&M Including Fuel	20,587	22,730	23,681	30,629	36,745	38,829	38,484	40,387	42,824	45,950
Total Expenses	20,587	22,730	23,681	30,629	36,745	38,829	38,484	40,387	42,824	45,950

Revenues are derived from current rates and the sales growth, increases for fuel surcharges and increases to meet a target return on investment. The revenues without a rate increase are illustrated on the table below:

Table 46 - Revenues without Rate Increase

	Units	Formula	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Revenues												
Electricity Revenues												
Total MWH Sales	MWH	Sources	52,293	57,294	60,594	62,005	63,914	68,324	72,806	76,732	80,869	85,230
Current Average Revenue/kWh	Cents/kWh	Rev/Sales	65.46	64.73	64.27	70.11	72.49	72.49	72.49	72.49	72.49	72.49
Total Revenues at Current Rates	$	Price x Quan	34,229	37,088	38,944	43,470	46,334	49,531	52,780	55,626	58,626	61,787
Current Fuel Charge Rate	Cents/kWh	Expenses	0.16	0.14	0.14	0.22	0.20	0.21	0.24	0.23	0.23	0.24
Base Fuel Charge	Cents/kWh	Expenses	0.16	0.14	0.14	0.22	0.20	0.20	0.20	0.20	0.20	0.20
Fuel Surcharge	Cents/kWh	Expenses	-	-	-	-	-	0.01	0.04	0.03	0.03	0.04
Fuel Surcharge Revenues	$	Price x Quan	-	-	-	-	-	993	3,227	2,560	2,494	3,157
Total Electric Revenues without Rate Chages	$	Sum	34,229	37,088	38,944	43,470	46,334	50,524	56,007	58,186	61,119	64,943
Added Revenues from Rate Increases			0	0	0	0	0	0	0	0	0	0
Other Revenues			0	0	0	0	0	0	0	0	0	0
Total Revenues			34,229	37,088	38,944	43,470	46,334	50,524	56,007	58,186	61,119	64,943
Return on Equity Result				9.07%	23.80%	12.53%	-20.00%	10.47%	21.43%	14.93%	9.59%	7.67%
EBIT			-	9,252	9,614	6,344	3,828	5,727	10,697	10,058	9,142	8,819
Net Plant			80,499	85,990	84,152	88,855	76,469	84,784	93,193	109,008	116,861	124,968
ROA Result			0.00%	10.76%	11.42%	7.14%	5.01%	6.75%	11.48%	9.23%	7.82%	7.06%
ROA Target								10.00%	10.00%	10.00%	10.00%	10.00%
Ending Revenue per kWh			654.56	647.33	642.70	701.07	724.94	739.48	769.26	758.30	755.78	761.98

Section 5: Results of the Rate Impact Modelling in Cases with Renewable Resources

This section reviews selected results from cases where renewable resources are deployed. The results are presented for cases in which renewable technologies are deployed compared to a status quo case with any renewable resources that use similar assumptions. Note that we distinguish between the term base case and status quo case because the status quo case without renewable resources may be run for multiple oil price and load growth scenarios. For example, the base case includes most likely case assumptions with

respect to items such as oil prices. The status quo case refers to the status of renewable projects rather than to general assumptions. For example, if we want to evaluate renewable resources in a high oil price environment, the status quo case is first revised to include high oil prices. Next, the renewable assumptions are added to the high oil price case so that a comparison can be made under a high oil price environment.

This section reviews selected results of the rate impact model for each of the utility companies analyzed. In discussing the analysis, we highlight important assumptions and mechanics of each of the models. We discuss different modeling issues for the different systems.

Volume II includes the models for each system. These models can evaluate each issue for each company. The review of the results of each model illustrates the status of the database for each model. The models are intended to be used as practical on-going tools rather than simple presentation of results for a single study. We have tried to structure the rate impact model to be easy to modify and updated with additional financial and operating data from the utility companies, modified data on renewable energy projects and alternative assumptions with respect to fuel costs, load growth, diesel costs and so forth.

Chapter VI - Template Documents

Purposes and Uses

The items for which we developed templates are indicated in **bold** font. Items for which we have examples are indicated in italics. The most common reasons for elimination of a document from the final list of templates were (1) infrequency of use and (2) insufficient commonality of content to make templates particularly useful. Others papers are (3) not distinctive where RET projects are involved. That is, customary contract or other document forms can be used. However, we are not qualified (and do not purport) to offer legal guidance, especially advice that accounts for the particulars in the laws of various Caribbean countries.[34] Where appropriate, items in the "Document" column for which templates were not prepared are designated by the number assigned above to the reason noted above. <from chapter 1>

Typically, a developer seeking RET project financing approaches a lender with a package that includes a fairly common slate of fundamental transaction documents. They may

[34] Time limitations forced some prioritization, and high priority was not given to the duplication of numerous standard legal documents that have little or no RET-specific content. The combination of legal issues and time constraints led us to eliminate some of these types of documents from the template list.

range from complex plans for a facility using a novel technology to simple (but important) term sheets for the deal or a loan. Our purpose was to identify the most important of those documents and to replicate, in templates for those documents, the critical elements of a proposed transaction package. The documents for which templates are presented were selected through a review of project financing deals from around the world, our review of numerous standard (and unique contracts) for power sales and project finance, and our interviews with RET transaction stakeholders.

The list has been narrowed to the essentials. While any transaction may involve additional instruments, nearly all will require the ones for which templates are presented. Each of the template documents is addressed in the following paragraphs. The template documents themselves included in Volume II.

The peculiar characteristics of a particular project may lead lenders, developers, or off-taking utilities to demand supplementary provisions, special commitments, or additional documentation to achieve an adequate level of comfort with a project and it's financing. Some of these other possible transaction instruments -- which are not universally used, but may be required by the circumstances of a particular project -- are discussed below. Templates for these less common items were not developed. But, the information presented alerts stakeholders to the pertinent issues associated with their use.

The template documents developed in this project are not intended to constitute legal advice. Indeed, no template could even pretend to serve that function, since the CARICOM nations have distinctive legal requirements, regulatory regimes, and market structures. The templates provide a businessman's guide to the issues and some possible resolutions associated with RET project financing. Any legally binding transaction (and the preparation of appropriate documentation) should be conducted with appropriate legal counsel.

Development of the Templates

When we began the task of preparing model template documents for project financing transactions, it appeared to be particularly daunting. We anticipated the complexities presented by different technologies, by varying characteristics and requirements of potential lending institutions, and by a full continuum of regulatory constraints across the Caribbean. A single document that would work for all technologies, projects, bankers, and utilities would be a virtual impossibility -- or impossibly long. In developing our templates we have accordingly been impelled to make choices. At the same time, the realities of financing and the documents used in the industry resolved many of the matters expected to be most troublesome. Undoubtedly, the greater part of the simplification process was due to choices made in the development process. Some circumstances were so unusual and some provisions or documents lacked sufficient commonality to be productively addressed in a "template" for future users. Other aspects of the transaction were matters common to ordinary commercial transactions that are uniquely affected by the fact that it involves a renewable project. Moreover, the principal differences among

these ancillary documents are in the “boilerplate” – the domain of lawyers gathering the arcane peculiarities of local law into legal provisions that only marginally affect the economic and technical aspects of a deal. These choices had their greatest effect on the number of documents and provision presented as templates.

The substantive issues raised by templates were affected by different considerations. The most significant substantive choices and strategies reflected in the templates are these. First, we focused on the essentials. Rather than let the perfect be the enemy of the good, we deployed our finite resources and used the available time to pinpoint and present the fundamental elements of a deal. While an omitted document or provision may prove critical in a specific transaction at some point in the future, we did not attempt to identify and to incorporate in a single document all possible problems (and a solution). During our research, we encountered valiant attempts to do so in other contexts. (*See, e.g.*, the EEI model contract in Volume II) The result was confusing, serving mainly as a à *la carte* menu of many possible provisions. Second, simple approaches that captured the essence of an issue and a fair resolution were preferred. Lawyers can, and likely will, add more documents and more words in any deal. Our presentation is of the business issues important to the dealmakers. Finally, we had to choose one perspective in negotiated transactions among different parties. For the most part, we have taken the perspective of the local developer. At the same time, we have not neglected other views, and have tried to present templates that are not burdensome of unfair to any party.
The development of the template transaction documents has been refined using input from regional stakeholders. We have interviewed utility companies, banks, developers and manufacturers active in the region. The terms required by financial institutions and utilities for transaction documents were also the subjects of inquiry in the regional surveys conducted as part of this project. While that effort is not complete, we have tried to take the available lessons into account in the templates. In our discussion, our analyses, and in other included work products, we present not only the terms of the template transactions, but also ranges of representative loan rates, energy prices, and capacity payments, as well as critical off-taker interconnection and security requirements.

We began the development of template documents by reviewing power purchase agreements and other transaction documents from the region and elsewhere. We examined documentation for both renewable and non-renewable energy technology transaction. We obtained numerous actual and industry model documents: among them were PPAs, financing term sheets, offering memoranda, operation and maintenance specifications, interconnection arrangements, and project finance spreadsheet models. Naturally, we have looked to regional transaction to the maximum possible extent. The Wigton wind farm project in Jamaica has been a particularly useful case study, in no small part because principals on that project have been generous with their time and insights. ADICA’s contacts in large multinational banks and financial institutions helped gain perspective on transaction structures, and on which ones would be most useful in the CARICOM region. All of these resources contributed to the development of the template documents. Selected examples of these and other resources used are collected in Volume III of the Final Report.

The list of documents and resources shown below relates principally to non-recourse financing arrangements, the form most relevant to the types of projects in the CARICOM pipeline. This slate of documents was evaluated in light of input from various sources we consulted (both inside and outside the region). The slate of documents for which we made templates represents a subset of this list. The items for which we developed templates are indicated in **bold** font. The most common reasons for elimination of a document from the final list of templates were (1) infrequency of use and (2) insufficient commonality of content to make templates particularly useful. Others papers are (3) not distinctive where RET projects are involved. That is, customary contract or other document forms can be used. However, we are not qualified (and do not purport) to offer legal guidance, especially advice that accounts for the particulars in the laws of various Caribbean countries.[35] Where appropriate, items in the "Document" column for which templates were not prepared are designated by the number assigned above to the reason noted above. <repeated paragraph from 1st page of this chapter>

Table 47 - Transaction Documents

FINANCING TRANSACTION	DOCUMENT	COMMENTS
Non-Recourse Off Balance Sheet Project Finance		***N.B.*** *One problem common to nearly all project finance structures is that, in general, legal costs and document development costs is much the same for a relatively small plant as for a larger facility.*
	Purchased Power Agreement	·This most important document in gaining financing may contain prices based on avoided costs or fixed capacity and energy prices.
	Enterprise Formation Papers (2)	·The project finance structure is based on the formation of a special purpose entity that shields the sponsor and facilitates commitment of all project assets and revenue to investors and lenders. ·The formation process of such an entity is dictated by the laws of the project country. The papers may vary, but they must satisfy the purposes noted. ·All pipeline projects have completed this stage.
	Term Sheet	·A concise summary of the economic terms of a proposed project financing. ·Term Sheets are sometimes the basis for decisions or negotiations on a financing, though a full package of documents may be appropriate for the most effective presentation to potential financing sources.

[35] Time limitations forced some prioritization, and high priority was not given to the duplication of numerous standard legal documents that have little or no RET-specific content. The combination of legal issues and time constraints led us to eliminate some of these types of documents from the template list.

FINANCING TRANSACTION	DOCUMENT	COMMENTS
	Construction Loan (3)	·The construction loan funds building of the project. It specifies draw down provisions, required equity contributions, credit spread, etc. ·In project financing arrangements, a permanent loan may replace the construction loan once the facility is operational.
	Permanent Loan	·In project financing, this debt is incurred on the basis of revenues from the operational project. · Sometimes replaces a related construction loan. In addition to loan covenants and repayment terms, the document defines the priority of claims on project cash flow.
	Interconnection Agreement	·Interconnection with the grid to which energy production from the project will is a precondition to delivery of and revenues from energy output. ·In most cases, given the size and complexity of Caribbean grids, the necessary provisions can be incorporated into the PPA.
	Term Sheet	·A concise summary of the economic terms of a proposed project financing. ·Term Sheets are sometimes the basis for decisions or negotiations on a financing, though a full package of documents may be appropriate for the most effective presentation to potential financing sources.
	CDB Development Loan	·Although loans of this type can be valuable in getting projects off the ground, they can distort the project assessment of lenders, making commercial financing more difficult. ·
	Equipment, Procurement & Construction (EPC) Contract (2)	· For RET equipment, manufacturers may offer the best deals, using their own standard agreements. ·Such manufacturer's deals may be fixed price, turnkey contracts with favorable financing terms.
	O&M Contract	·Local maintenance of RET projects is a worthwhile goal, but manufacturer support is more practical, and would typically be dome under a standard contract.
	Information Memorandum	·The information memorandum is not a contract, but it is a main marketing tool for potential sources of financing. It describes the project, the market and economic projections that form the basis for project finance. A sample information memorandum was prepared and is included.
	Hedging Contacts	·If the PPA contract is based on avoided costs derived from volatile fuel costs, the price and revenue risk can be mitigated through hedging. ·This risk allocation can be handled through provisions in the PPA if the PPA price is based on variable costs, such as avoided cost or fuel costs. With a fixed PPA price, the need for hedging (for the developer) is eliminated.

FINANCING TRANSACTION	DOCUMENT	COMMENTS
	Licenses and Zoning	·The necessary permits vary among jurisdictions, but are always necessary. The forms are dictated by the local authorities. ·Among the issues to be covered are easements for location of the facilities and for operation or maintenance, clear water rights as to downstream users whose flow may be curtailed, and environmental assessments required by applicable codes.

The following paragraphs examine some of the issues relating to the particular documents in greater detail.

Purchased Power Agreements (PPAs)

The Purchased Power Agreement between a special purpose entity that owns the renewable resource technology production facility and a purchaser of the project's output is generally the most important document in securing commercial financing for the project.

For on-grid RET generation projects seeking commercial financing, a purchased power agreement is an essential component of the development process. First, since the purpose of the project is usually to produce electricity for sale, some measure of assurance that the project's output will find a buyer is a prerequisite to the substantial capital investment needed for construction.[36] Second, the PPA is just as important for purposes of commercial financing, which typically is a larger fraction of the total project investment than is equity capital. Certainty of a revenue stream that is sufficient for timely coverage of project financing loan interest and principal payments is a critical factor in financial institutions' lending decisions.

Most renewable energy technologies rely heavily on natural phenomena – sunlight, wind, geothermal heat, or hydro power -- for the energy that will be converted to electricity. Fundamental characteristics of these energy sources constrain the production of electricity in ways that impel certain differences from traditional fossil-fuel generation PPAs. Even projects using renewable or recycled fuels (*e.g.*, bagasse and other renewable fuels) are distinctive in their production characteristics. Accordingly, PPAs for RET generation projects will reflect those characteristics in the terms of the agreement.

The principal difference is the variability in production output. Unlike combustion generation, most RET generation cannot be ramped up or down in response to sudden changes in demand. Although the output of RET facilities is fairly predictable over long

[36] Merchant RET projects, built without a known buyer, are likely to be rare in the monopoly (or recently opened) CARICOM electricity markets.

periods of time, their production at any given moment will mirror the available energy from the RET source – for example, river levels in run-of-river plants or wind speed for wind turbines. Even combustion fueled renewable generation may share seasonal output variations with other RET projects. For example, the availability of bagasse for fuel may depend upon agricultural cycles, just as hydro power will track seasonal flows of water. Those fundamental energy sources cannot be manipulated on demand to produce greater or lesser amounts of electricity (absent complementary compensating technologies like batteries, reservoirs or linked arrays of the RET generators).

As a result, the PPA for a RET project may commit the producer to a lesser quantity of electricity than can be produced to match the amount that can be assuredly produced, given the variability of the principal energy source. For the same reason, capacity payments – money for production capability available on demand – are unusual in RET projects. Installations like wind farms may be able to assure a certain level of production through the aggregated performance of dispersed units. Such installations might be able to earn some capacity payments, but the capacity contracted is likely to be significantly less than the maximum potential of the entire installation.

PPAs for RET projects must necessarily reflect some flexibility on the part of producers and purchasers to accommodate the limitations of RET projects while gaining the economic and environmental benefits they can offer. We anticipated at the beginning of this effort that the PPAs for different technologies would contain noticeable differences in their terms. Instead, we have found that changes to PPAs to accommodate these performance distinctions are not dramatic. The implications of technology differences can be – and generally are – addressed in technical appendices that are regularly incorporated into PPAs.

Interconnection Agreements

As with the structure of PPAs for RET projects, our findings were not entirely consistent with our expectations. Interconnection with the grid of the purchasing utility is a precondition to delivery of RET project energy and the resulting revenue stream. Interconnection of the project to the system is the first concrete implementation step in capturing the value of the PPA underlying the project. We had anticipated that the importance of that interconnection would be reflected in the scope and complexity of the interconnection contract. In fact, the interconnection process has been handled more efficiently by the developer and utility communities.

On large systems complex transmission flows and the myriad problems that can result when a new generation source is added in parallel operation can require the deployment of technical and personnel resources to continually monitor the effects of changes in production output and power quality. The utility systems of the CARICOM countries are much smaller and less complex than those in other nations that have incorporated renewable generation technologies.

In comparing interconnection arrangements on larger (U.S.) systems and an interconnection agreement actually used in Jamaica, the substantive provisions to govern the relationship between the producer and the system operator are very similar. For example, despite a very large difference in the length of the U.S. Federal Energy Regulatory Commission (FERC) proposed standard interconnection agreement for small generators and the interconnection agreement used in Jamaica, we found that the substantive provisions tracked very closely. The principal cause of the difference in document length was the legal boilerplate. Those legal provisions relate to matters that are largely independent of generation technology.

The technical requirements that were particularized to the technology and technical characteristics of the generation project were handled similarly in both the longer separate agreement proposed by FERC and by the provisions incorporated in the PPA for the Jamaica project. In both agreements, technical appendices (for which templates are meaningless) contain the core operational requirements. In the Jamaican arrangement, however, the appendices and the contract obligation provisions that incorporated the interconnection technical appendix were a part of the PPA. The parties to the Jamaican RET project interconnection arrangement did not require a separate agreement, on what is by far the largest system in the CARICOM region. It is unlikely that the complexity of the connecting system or the issues raised by RET technologies cannot also be handled within the PPA.

The substantive economic and technical issues that might be affected by differences in the characteristics of RET projects (as opposed to fossil fuel generation) can be accounted for in elements of the PPA. The unusual capacity characteristics of RET generation are reflected in the absence of (or the lower amounts for) capacity payments from the utility. Energy-only contracts eliminate the issue of whether renewable energy power can be relied on to be available and dispatchable as needed by the utility. Any technical problems that may arise from the sometimes unpredictable output level of the RET project can be addressed in technical appendices, with performance failures reflected monetarily in offsets or contract penalties.

If a separate agreement is needed for any reason, the quite comprehensive small generator interconnection agreement proposed by FERC is included in Volume __.

Operations and Maintenance Agreement/Specifications

The operation of the RET project is a matter of some concern to the lender, since under project financing the revenue from the project's production output is the lender's principal or (in non-recourse deals) sole means of repayment. Lenders will insist on proof that the developer has the requisite expertise to assure operation of the facility at a level adequate to cover the agreed multiple of interest and principal payments. Alternatively, the developer can retain the services of an operator satisfactory to the lender. Depending on the technology and equipment used in the project, there may be local contractors capable of performing these duties.

Similar requirements exist with respect to the maintenance of the project equipment. Unplanned outages cut into the project output and revenues, jeopardizing timely payments to the lender. Small RET projects often use off-the-shelf or built-to-specifications generation equipment. The generous nature of some manufacturer incentives can be a critical factor in the selection of the equipment used. (*See* the discussion in Chapter __.) The contract for the continuing maintenance of the equipment may be bundled with available favorable sales terms. Like the discounts for purchase of the manufacturer's equipment, bundled maintenance agreements have the effect of promoting use of the industrial manufacturing capacity and the labor forces of the manufacturer's country. The availability of local technicians or professionals to perform these duties can facilitate RET development from the perspectives of both lender and developer.

The crux of the maintenance obligation is to achieve production for an adequate portion of the year to cover loan payments in a timely manner. This is accomplished in some contracts through operations and maintenance specifications in the PPA, an obligation of the developer whether it uses a subcontractor or not. If a third party is used, a separate contract for the maintenance or operations and maintenance functions is needed. Strictly speaking, this would be the O&M contract.

Construction and Permanent Loan Agreements

In our conversations with bankers, most have stated that their financial institutions have form agreements of their own design and composition. More to the point, they indicated that their in-house form agreements are routinely substituted for forms of agreement proposed by parties seeking financing. The development of a template for these agreements would serve mainly to educate potential developers about the content of commercial loan arrangements, something a knowledgeable developer should already have encountered. In addition, it may be a useful structure to assist a developer in thinking through the financial aspects of his proposal. We have included a commercial loan agreement for those purposes. It does not purport to be a template for use by potential financiers, as that use is unlikely, but it does provide some frame of reference about what such agreements might reasonably expected to contain.

Term Sheets

Term sheets summarize each of the economic elements of a proposed financing arrangement, along with any performance requirements that have direct economic consequences of importance. The terms are usually presented as bullet points, or in some other very concise format, without the legal boilerplate of a contract.

The term sheet is often the working document from which negotiations over the economic terms of financing deal are conducted. It precedes and often defines the

subsequent contractual agreements. For that reason, a template Term Sheet was developed to reflect the terms of a hypothetical RET project financing.

Other Transaction Documents

The project financing arrangements of greatest interest to local developers in the Caribbean are, of course, non-recourse arrangements. In a non-recourse lending arrangement, in the event of a default on loan repayments, the lender may not seek recourse to the sponsor of the project or an enterprise affiliate of the project developer. Recourse is available only to the assets and the revenues of the separately organized project enterprise.

In limited or full recourse financings, there is a project sponsor to which (or to the assets of which) lenders can turn for performance of loan obligations, if that becomes necessary. In projects involving high risk, limited recourse financing is mere common. A strong sponsor for a proposed project would obviate many of the difficulties in obtaining financing local RET project developers are encountering. However, our focus has been so much if not more on non-recourse financing, because most of the active RET developers in the region (as indicated by the CARICOM pipeline projects, and limited utility RET developments) are not affiliated with large organizations with recourse resources. Still, some aspects of limited or full recourse financing arrangements could be incorporated into agreements governing development projects with suitable characteristics. For projects that could not obtain financing without some form of guaranty or additional financial assurances, limited recourse may be the least painful alternative to the demise of the project.

The following chart summarizes some important characteristics of several limited or full recourse arrangements and the associated documents.

Table 48 - Recourse Transaction Documents

FINANCING TRANSACTION	DOCUMENT	COMMENTS
Limited or Full Recourse Off Balance Sheet Project Finance		A sponsor that uses its balance sheet to finance a project gives the bank additional security in the form of recourse to resources in addition to the revenue and assets of the project.
	Guarantor Support Agreement	·Specifies the degree of support from a guarantor and the terms under which the guarantor will provide additional cash to the project.
On Balance Sheet Project Finance		·On-balance sheet financing arrangements are "synthetic" project finance transactions. Money is provided by a larger (possibly affiliated) enterprise instead of a financial institution, using a structure that resembles a typical project financing.
Leveraged Lease		·If the tax laws of a country provide tax advantages

FINANCING TRANSACTION	DOCUMENT	COMMENTS
		for development of a facility, which benefits the developer cannot use, those benefits may be transferable to another party in exchange for financing assistance. ·The legal and tax issues are complex and compliance may be strictly enforced.
	Lease Agreement	·The lease agreement defines the lease rate (similar the interest rate plus the debt repayment of a standard loan) as well as the asset transfer conditions, plus other provisions that are similar to loans arrangements. ·The form and substance of the lease arrangement can determine whether the tax advantages are available.
Operating Lease		·Traditional financing for small, non-revenue projects like solar water heaters can be unrealistic or prohibitively expensive. ·Lease financing can provide an alternative loan vehicle for such projects.
Joint Ventures		·In general, joint ventures are beneficial when two parties can bring complementary strengths to a transaction – *e.g.*, a developer with expertise in renewable technology and a utility company experienced in financing. ·The documents in such cases are defined by the particular contributions of the parties to the development.
	Joint Venture Agreements	·Defines what contributions are made by the parties and how the risks, returns and performance duties of the project are allocated among the participants.
Equity Investment Funds		·In addition to the debt financing vehicles identified above, equity trusts may look at power projects. ·Small RET projects are likely to be of interest mainly to funds specifically dedicated to renewable resources.
Other Equity Investment		·In countries that have established emissions credit trading regimes, renewable resources may generate valuable emission reduction credits that could support financing. ·This financing source may grow in importance and availability as the Kyoto environmental protocols are implemented.
Supplier Capital		·Financing in the form of price discounts, favorable loan terms, or investment capital is a principal source of capital for projects in developing countries that will use capital equipment manufactured in other countries in need of export markets.

Financing Transaction	Document	Comments
Multilateral Credit Agencies		·Multilateral credit agencies are most useful in providing funding that ameliorates political or new technology risks or that internalizes societal benefits in a way that facilitates commercial financing. ·An important function is providing insurance for perceived political risks in financing projects in developing countries. Such agencies may also provide direct loans in some cases.

Information Memoranda

Although information memoranda are most often used in the early, conceptual stages of project development -- and do not diminish the need for quantitative support like that we have developed for the pipeline projects -- they can be useful in approaching governmental or multilateral sources of loans or grants. These memoranda collect in a single presentation the project-specific information and documents needed to give the best chance for successful commercial financing. Each includes a project description, results of quantitative analyses, and proposed terms and documents for the desired financing.

The templates discussed above are included Volume II of the Final Report. Examples of other documents that also can be used as models, like the templates, are included in Volume III.

ANNEX I - Financial Survey

General Survey

FIRST CONTACT (GENERAL QUESTIONNAIRE)

{Ideally, the initial e-mail communication would come from a CARICOM address, although Adica can handle associated administrative tasks. Showing CARICOM as the source should assure name recognition and enhance response rate.}

===

[Contact Name and Address]:

The CARICOM Secretariat is contacting financial institutions in the Caribbean to ascertain their interest in financing alternative energy projects that produce electricity from solar, wind, geothermal, small hydro, or bio-mass (landfill and bagasse) resources. CARICOM believes that information from your response the attached attitudinal survey will help developers of energy projects make loan applications that are sensible from your perspective, that include reasonable terms (debt leverage, debt tenor, covenants, credit support) and that contain the documents you require. Furthermore, CARICOM will use this survey to make potential electricity generation projects more bankable through encouraging developers to improve contracts and other credit support.

CARICOM's initial work in mobilizing developers suggests that there may be a debt financing need of at least US $200 million for feasible, identified, economically viable projects in the region. Further, we believe that financing these projects through regional institutions is crucial to the development of this energy sector. In other countries, lending to alternative energy producers has been profitable for financial institutions because of the credit spreads, transaction fees, a low loss experience, the collateral security of hard assets providing essential electricity generation services and off-take agreements with electric utility companies.

The attached questionnaire is designed to gauge your level of interest in expanding your commercial loan portfolio into this growing energy sector and to identify those terms and conditions that would most affect your lending decisions. When developers can understand terms more likely to be attractive to financial institutions, financial institutions like yours can expect to see a number of good proposals and to spend less time screening out poor candidates.

We would appreciate an opportunity to discuss these matters with you in a telephone interview. We will ring you during the week of [__________] to arrange a time for that conversation. If, at that time, you have had an opportunity to review the questions and have the requested information at hand, we can discuss it immediately -- if that is more convenient for you. If the telephone interview should be conducted with somebody else in your organization, please assist us by responding via e-mail or post to the addresses below identifying the more appropriate person.

For further information:
Dr. Roland R. Clarke
Project Manager, CREDP
CARICOM

rclarke@caricom.org,
Tel: 011 +592 22 69281 x 2631

{Attachments -- General Questionnaire, Sample Term Sheet}

CARICOM Questionnaire to Selected Financial Institutions

The questionnaire is divided into four sections, each focusing on a different aspect of your financing practices. The first section addresses general demographic issues regarding your lending preferences. The second section deals with required loan documentation. The third section requests responses on the structure and size of loans while the final section deals with underwriting and loan pricing.

Before discussing the various topics, we think it is helpful to clarify our meaning or certain terms used in the questions below:

> ***Project finance*** means a loan arrangement that is tied to a specific asset and supported by cash flow from a number of contracts, including a long term contract with a utility company, an operation and maintenance contract and a contract with a construction company to build a project.
>
> ***Alternative energy*** refers to renewable electricity technologies that generate power using wind, solar, biomass, geothermal or water to generate electricity.
>
> ***Purchased Power Agreements (PPA)*** are contracts between an electric utility purchaser (known as the off taker) and a company that constructs and operates a generation facility on an independent basis.
>
> ***Project Sponsor:*** The project sponsor is the project's equity investor and is generally the company that develops the project. If the project sponsor is not a utility company, the sponsor is known as a ***non-utility developer***. For purposes of this questionnaire, the project sponsor is the party who is applying for the loan.
>
> ***Construction Loan:*** A loan that the covers the construction phase of a project (which may last from six months to a few years), where developers receive money on a monthly basis (draws) to cover funding of equipment purchases and installation costs. The construction loan is repaid from a permanent loan when the project commences operation.
>
> ***Permanent Loan:*** A long-term loan that begins after the project begins commercial operation, and can have a tenor (the period before which the loan is fully repaid) of between 7 and 30 years. The permanent loan generally is ***non-recourse*** to the project sponsor, implying that only cash flows from the project are the re-payment source of the loan.

I. Demographics and Interest in Alternative Energy

1. Have you evaluated project finance transactions for electric power companies (either conventional oil plants or alternative technologies) in the past? Yes ☐ No ☐

2. Are you interested in providing loans to the renewable industry? Yes ☐ No ☐

3. Would you be interested in receiving loan proposals from electric utility companies in the region that are developing electricity generation projects which use alternative energy sources? Yes ☐ No ☐

4. Would you be interested in receiving financing proposals from non-utility developers that are developing grid-connected electricity generation projects that use alternative sources of energy? Yes ☐ No ☐

5. Would you be interested in receiving financing proposals from the Caribbean hotel sector that are installing solar water heaters? Yes ☐ No ☐

If the answer to all of the above questions is no, there is no need to answer the remaining questions.

6. Please provide the contact information for the person at your bank to whom contact should be made by developers of alternative energy and to whom financing proposals should be sent.

   Name ____________________
   Title ____________________
   Phone Number ____________________
   E-mail ____________________
   Address ____________________
   ____
   ____

7. In which Caribbean Countries are you interested in doing business:
   - ☐ Antigua and Barbuda
   - ☐ The Bahamas
   - ☐ Barbados
   - ☐ Belize
   - ☐ British Virgin Islands
   - ☐ The Republic of Cuba
   - ☐ Dominica
   - ☐ Grenada
   - ☐ Guyana
   - ☐ Jamaica
   - ☐ Montserrat
   - ☐ St. Kitts and Nevis
   - ☐ St. Lucia
   - ☐ St. Vincent and the Grenadines
   - ☐ Suriname
   - ☐ Trinidad and Tobago
   - ☐ Turks and Caicos Islands
   - ☐ All of the above

8. If you have branch offices in other countries to whom we should direct this questionnaire, can you provide the contact information for the person at the regional bank to whom contact should be made:

Name	______________________
Title	______________________
Phone Number	______________________
E-mail	______________________
Address	______________________
	______________________
	______________________

9. Funding of projects requires loans for the construction phase before the plant obtains commercial operation, and permanent financing after the plant is operational. Do you prefer:
   - ☐ Construction loans
   - ☐ Permanent loans that begin after construction
   - ☐ Loans that cover both construction and operation
   - ☐ Either permanent or construction loans

10. Some of the independent developers of alternative energy projects who apply for loans may be local utility companies, others may be locally owned companies that are not utility companies, others may be foreign energy companies, and still others could be joint ventures. Would you only lend to sponsors who are:
    - ☐ Local utility companies with whom you currently do business
    - ☐ Corporations wholly owned by investors in your country
    - ☐ Joint Ventures with a large company
    - ☐ No particular preference

11. When you make loans for more than $1 million, do you generally:
    - ☐ Hold the entire loan until it is repaid
    - ☐ Form a syndicate with other banks as the agent bank
    - ☐ Form a syndicate with other banks as the participant bank
    - ☐ Syndication depends on many factors, the loan could be either syndicated or held

II. Loan Application Process and Documents

12. What documents and information should a developer provide to you in requesting a loan:
    - ☐ Draft Term Sheet
    - ☐ Draft Loan Document
    - ☐ Feasibility Study
    - ☐ Purchased Power Agreement
    - ☐ Operation and Maintenance Agreement
    - ☐ Financial Projections
    - ☐ Financial Reports of Sponsors
    - ☐ Incorporation Papers
    - ☐ All of the above
    - ☐ Other ______________________________

13. CARICOM is developing templates of the customary documents for financing alternative electricity generation projects. Which sample "template" transaction documents would you be interested in receiving?
    - ☐ Power Purchase Agreement (PPA)
    - ☐ Information Memorandum
    - ☐ Loan Agreements
    - ☐ Detailed Project Finance Description
    - ☐ Engineering Procurement Construction Contract
    - ☐ Summary PPA and Loan Term Sheets
    - ☐ All of the above
    - ☐ None of the above

If the answer to the above question is "none of the above" you can skip the next question.

14. Would you be interested in commenting on drafts of the financing and PPA templates that we are developing? Yes ☐ No ☐

If you are not interested in construction loans, skip the next two questions.

15. What do you expect is the typical time requirement for approval of a construction loan, assuming the basic underwriting requirements such as purchase power agreements and financial projections are provided?
    - ☐ 1-2 months
    - ☐ 3-6 months
    - ☐ 7-12 months
    - ☐ More than 1 year

16. What do you expect is the typical time requirement for approval of a permanent loan, assuming the basic underwriting requirements such as purchase power agreements and financial projections are provided?
    - ☐ 1-2 months
    - ☐ 3-6 months
    - ☐ 7-12 months
    - ☐ More than 1 year

17. How early in the development process of a plant would you like a sponsor to contact you?
    - ☐ Not until all major contracts are signed
    - ☐ Early in the process before the feasibility study
    - ☐ When the agreement in principle has been established on the PPA, the construction terms and other major contracts

    Comments ______________________________

III. Loan Size and Structure

If you answered that you are not interested in construction loans, skip the next five questions.

18. If you are interested in making construction loans to alternative energy projects, would you prefer the loan to be denominated in:
    - ☐ Local Currency Only
    - ☐ US Dollar Currency Only
    - ☐ Euro Currency Only
    - ☐ Either Local, USD or Euro Currency

19. What is the approximate smallest size loan you deem commercially viable for a construction loan?
    - ☐ 0 – $1 million
    - ☐ $1 million – $5 million
    - ☐ $6 million – $10 million
    - ☐ $11 million – $25 million
    - ☐ More than $25 million

20. What is the approximate largest size loan that you put on your books for a construction loan?
    - ☐ 0 – $1 million
    - ☐ $1 million – $5 million
    - ☐ $6 million – $10 million
    - ☐ $11 million – $25 million
    - ☐ More than $25 million

21. What type of interest rate would you implement on construction loans (fixed or floating rate)?
    - ☐ Fixed rate only
    - ☐ Floating rate only
    - ☐ Fixed or floating rate
    - ☐ Floating rate with interest rate swaps
    - ☐ This is evaluated on a case by case basis

22. What covenants would you require in a construction loan agreement?
    a.) ______________________________
    b.) ______________________________
    c.) ______________________________
    d.) ______________________________
    e.) ______________________________

If you answered that you are not interested in permanent loans, skip the next seven questions.

23. If you are interested in making permanent loans to alternative energy projects, would you prefer the loan to be denominated in:
    - ☐ Local Currency Only
    - ☐ US Dollar Currency Only
    - ☐ Euro Currency Only
    - ☐ Either Local, USD or Euro Currency

24. What is the approximate smallest size loan you deem commercially viable for a permanent loan?
    - ☐ 0 – $1 million
    - ☐ $1 million – $5 million
    - ☐ $6 million – $10 million
    - ☐ $11 million – $25 million
    - ☐ More than $25 million

ADICA CONSULTING

25. What is the approximate largest size loan that you put on your books for a permanent loan?
- ☐ 0 – $1 million
- ☐ $1 million – $5 million
- ☐ $6 million – $10 million
- ☐ $11 million – $25 million
- ☐ More than $25 million

26. What type of interest rate would you implement on permanent loans (fixed or floating rate)?
- ☐ Fixed rate only
- ☐ Floating rate only
- ☐ Fixed or floating rate
- ☐ Floating rate with interest rate swaps
- ☐ This is evaluated on a case by case basis

27. What is the maximum tenor of a permanent loan that you would consider for an alternative energy project?
- ☐ Less than 3 years
- ☐ Less than 7 years
- ☐ Less than 10 years
- ☐ Less than 15 years
- ☐ Less than 20 years
- ☐ Less than 30 years

28. What is the maximum grace period (the period in which no debt re-payments are required) that you would consider in establishing the re-payment schedule of a permanent loan?
- ☐ No grace period
- ☐ Six month grace period
- ☐ Six month to one year grace period
- ☐ A 1-2 year maximum grace period
- ☐ A 3-5 year maximum grace period
- ☐ This is evaluated on a case by case basis

29. What covenants would you require in a permanent loan agreement?
   a.) ______________________________
   b.) ______________________________
   c.) ______________________________
   d.) ______________________________
   e.) ______________________________

30. What criteria would determine the size of a loan for project finance?
- ☐ Project collateral
- ☐ Debt service coverage ratio
- ☐ Debt to capital ratio
- ☐ All of the above
- ☐ This is evaluated on a case by case basis

Comments ______________________________
____
____

This question should be answered if project collateral is considered in sizing loans.

31. What is the minimum collateral that you would require for a permanent loan in project financing?
    - ☐ Less than 100% of the asset cost
    - ☐ Between 100% and 150% of the asset cost
    - ☐ Greater than 150% of the asset cost
    - ☐ Collateral is not required
    - ☐ This is evaluated on a case by case basis

    Comments ______________________________

This question should be answered if debt service coverage ratio is considered in sizing loans.

32. What is the minimum debt service coverage ratio (DSCR) that would be considered in determining the size of a loan?
    - ☐ Minimum DSCR of 1.2-1.4
    - ☐ Minimum DSCR of 1.4-1.6
    - ☐ Minimum DSCR of 1.6-2.0
    - ☐ This is evaluated on a case by case basis

    Comments ______________________________

This question should be answered if the debt to capital ratio is considered in sizing loans.

33. What is the minimum debt to capital ratio that would be considered in determining the size of a loan?
    - ☐ Maximum Debt/Project Cost of 90%
    - ☐ Maximum Debt/Capital of 80%
    - ☐ Maximum Debt/Capital of 70%
    - ☐ Maximum Debt/Capital of 60%
    - ☐ This is evaluated on a case by case basis

    Comments ______________________________

ADICA CONSULTING

IV. Loan Underwriting and Pricing

34. Would you identify some factors that you think would most affect your lending decisions on proposals for financing an alternative electric generation project (for example, technology risk, risk associated with wind, hydro, solar resources, construction cost risk, regulatory risk associated with maintenance of purchased power clauses).
   a.) ______________________________
   b.) ______________________________
   c.) ______________________________
   d.) ______________________________
   e.) ______________________________

   ☐ Risks depend on the transaction; it is difficult to identify risks without seeing real deals

   Comments ______________________________

35. While interest rates would obviously be market based, could you give a range in credit spreads above LIBOR or another benchmark that developers could expect for the ***construction*** phase?
   Credit spread range from ________ to ________ basis points, without guarantee
   Credit spread range from ________ to ________ basis points, with guarantee
   ☐ Credit spreads are market driven and depend on a variety of factors making it impossible to provide a spread
   Comments ______________________________

If last option is selected, do not ask next question.

36. Could you give a range in credit spreads above LIBOR or another benchmark that developers could expect for the permanent loan?
   Credit spread range from ________ to ________ basis points, without guarantee
   Credit spread range from ________ to ________ basis points, with guarantee
   ☐ Credit spreads are market driven and depend on a variety of factors making it impossible to provide a spread
   Comments ______________________________

37. How would the term of a purchase power contract affect the tenor of your loan?
   ☐ The PPA should extend for at least 5 years beyond the loan
   ☐ The PPA should extend for at least 7 years beyond the loan
   ☐ This is evaluated on a case by case basis
   Comments ______________________________

38. Please provide your reaction to the attached Term Sheet for a hypothetical lending transaction for an alternative energy project, using the policies and practices of your institution.

ADICA CONSULTING

Draft Template Project Financing Term Sheet

(Exemplar Terms Assumed)

BORROWER	▪ A special purpose enterprise created for a defined alternative energy project (Project), organized as a limited liability enterprise.
PROJECT COST	▪ Agreed estimated full cost of Project construction and commissioning of the Project located at __[Site Specification]__, in US$ or €.
EQUITY CONTRIBUTION	▪ Approx. 30% of Project Cost, to be paid into pool of funds at Closing. Source may be parent company or unaffiliated investor.
CREDIT FACILITIES	▪ Construction Loan for 70% of cost of construction. Remainder to be provided from equity, and from multilateral organization financing. ▪ Term Loan for unpaid Construction Loan amount on the Conversion Date.
SECURITY/COLLATERAL	▪ Senior security interest in all Project assets, including plant and equipment, PPAs for project output, other contracts or contract rights, and bank accounts.
CONSTRUCTION LOAN AMOUNT	▪ 70% of the pre-determined and agreed Project Cost.
TERM LOAN AMOUNT	▪ Outstanding Construction Loan amount on the Conversion Date at time Project becomes operational.
INTEREST RATE	▪ Construction Loan: LIBOR or US Prime + __% per annum ▪ Term Loan: LIBOR or US Prime + __% per annum
CONVERSION DATE	▪ Date on which the Construction Loan is due and is replaced by the Term Loan -- the earlier of the date the Project becomes operational or 36 months after the closing date for the Construction Loan. ▪ Term Loan contingent on plant being operational.
MATURITIES	▪ The Construction Loan will mature on the Conversion Date and the Term Loan will mature 10 years from the Conversion Date.
REPAYMENT	▪ The Construction Loan will be repaid from the proceeds of the Term Loan and from the pool of funds comprised of the equity contribution and other funds from, *e.g.*, multilateral agencies.
LENDER	▪ The loans will be made by a regional project finance institution underwriting the entire loan amounts or working with other financial institutions to underwrite the Project through syndication.
UNDERWRITING	▪ It is preferred that the Lender underwrite the entire amount of the loans. ▪ Alternatively, the Lender may be the leading member of a syndicate, with the loan amounts underwritten by cooperating financial institutions.

Detailed Survey

E-MAIL MESSAGE

{Sending the e-mails, but over the e-mail who is known to bankers in the region -- for name recognition and ease of reply}

===

[Contact Name]:

The CARICOM Secretariat is in the process of gathering information on project finance from selected financial institutions in the Caribbean who are leaders in energy lending. We are working with utility companies and project developers on practical ways to construct and finance a number of actual wind, solar, hydro, biomass and other alternative energy projects. CARICOM's initial work in mobilizing developers has confirmed that there may be a debt financing need of more than US$200 million for identified, economically viable projects in the region. Financing these projects through regional institutions such as your bank is crucial to the development of the renewable energy sector.

CARICOM believes information from responses to the attached survey will help developers of energy projects make reasonable loan applications that contain the information your bank requires. The information will also help project sponsors develop realistic financial parameters when making their assessment of investment possibilities. In addition, CARICOM will use information from your responses to consider the need for government guarantees and other credit support for loans to the sector.

We would appreciate an opportunity to discuss these matters with you in a telephone interview. We will ring you during the week of [_________] to arrange a time for that conversation. If, at the time we phone, you have had an opportunity to review the questions and it is convenient for you, we can discuss the survey immediately. If the telephone interview should be conducted with somebody else in your organization, please assist us by responding via e-mail or post to the addresses below identifying the more appropriate person.

<u>For further information</u>:

Dr. Roland R. Clarke
Project Manager, CREDP
CARICOM
rclarke@caricom.org
Tel: 011 +592 22 69281 x 2626 or x200 (Operator) 011
Direct: +592-225-0972
Fax: +592-226-7816

CARICOM Questionnaire to Selected Financial Institutions

Introduction

This survey is divided into six parts in order to help assure that developers of alternative energy projects work efficiently with your bank as the sector grows in size. The six sections of the survey include:

1. Demographics and general questions ***that assess your interest in various types of transactions***
2. Loan documents and the loan process during construction ***that ask about how you would like to administer loans during the construction phase of a project***
3. The underwriting process ***for evaluating the credit quality of alternative energy projects that are project financed***
4. Credit spreads ***and other pricing issues for project finance lending***
5. Loan Sizing, Syndication and Currency Denomination ***preferences for project finance loans***
6. Loan Structure Elements ***including the tenor of loans, the re-payment terms, covenants and debt service reserves***

Before delving into the questions, it is helpful to establish a common same meaning to a few terms:

Project finance means a loan arrangement that is tied to cash flow of a specific asset and is supported by a number of contracts, including a long term contract with a utility company, an possibly an operation and maintenance contract and a contract with a construction company to build the project.

Alternative energy includes renewable energy technologies for electricity generation technologies that use wind, solar, biomass, geothermal or water to generate electricity.

Purchased Power Agreements (PPA) are long-term contracts between an electric utility purchaser (known as the off taker) and a company that constructs and operates a generation facility on an independent basis. The contracts establish the quantity purchased and the price of the power.

Project Sponsor: The project sponsor is the project's equity investor and is generally the company that develops the project. If the project sponsor is not a utility company, the sponsor is known as a ***non-utility developer***. For purposes of this questionnaire, the project sponsor is assumed to be the party who is applying for the loan.

Construction Loan: A loan that the covers the construction phase of a project (which may last from six months to a few years), where developers receive money on a monthly basis (draws) to cover funding of equipment purchases and installation costs. The construction loan is a bridge loan that is re-financed with a permanent project finance loan when the project commences operation.

Permanent Loan: A long-term loan that begins after the project begins commercial operation, and can have a tenor (the period before which the loan is fully repaid) of

between 7 and 30 years. The permanent loan generally is ***non-recourse*** to the project sponsor, implying that only cash flows from the project are the re-payment source of the loan.

I. Demographics/General Questions

In the first section, CARICOM would like to ask a few questions about your general interest in lending to alternative energy suppliers, and your basic criteria for accepting a transaction.

A. Experience and general interest in project finance for the alternative energy sector

1. CARICOM understands that you have completed a transaction where an alternative energy project has a loan supported by a purchase power agreement. Can you briefly describe the project?

   ____
   ____
   ____

2. Are you interested in doing more business of this type? Yes ☐ No ☐

   a. Would you be interested in wind projects? Yes ☐ No ☐

      ____
      ____

   b. Would you be interested in small hydro projects? Yes ☐ No ☐

      ____
      ____

   c. Would you be interested in geothermal projects? Yes ☐ No ☐

      ____
      ____

   d. Would you be interested in solar projects where electricity is sold to the grid?

      Yes ☐ No ☐

      ____
      ____

   e. Would you be interested in solar water heating projects owned by hotels (the loans would be to the hotel sector)?

      Yes ☐ No ☐

      ____
      ____

   f. Would you be interested in biomass projects (landfill etc.)? Yes ☐ No ☐

      ____
      ____

B. Contacts

1. Is the person who should be contacted by developers the same for each of the types of projects?

   Yes ☐ No ☐

a. Who are the appropriate contacts at the bank for various different type of projects

i. Name ______________________________

ii. Title ______________________________

iii. Phone Number ______________________________

iv. E-mail ______________________________

v. Address ______________________________

____

____

vi. Name ______________________________

vii. Title ______________________________
viii. Phone Number ______________________________
ix. E-mail ______________________________
x. Address ______________________________
____
____

b. Is the person at the bank who should be contacted by alternative energy developers such as sponsors of wind farms the same person at the bank who would deal with hotels that install solar water heaters?

Yes ☐ No ☐

____
____
____

C. Geographic Scope of Loan Activity

1. In which Caribbean countries can you make loans?

____
____
____

2. Do you have branch offices in other Caribbean countries that may be willing to do business with alternative energy suppliers?

Yes ☐ No ☐

____
____
____

a. Can you provide the phone number, fax number, address and e-mail address of the appropriate branch office?

Name: ______________________________
Phone: ______________________________
Fax: ______________________________
E-Mail: ______________________________
Address: ______________________________
____
____

D. Sponsor Characteristics

1. Project sponsors could be independent developers from the region, foreign developers, utility companies or joint ventures. Are there certain sponsors that you would not lend to?

Yes ☐ No ☐

____
____
____

a. Would you lend to sponsors that are foreign owned companies (for example, UK utility companies)?

Yes ☐ No ☐

b. Do the sponsors have to meet any certain financial criteria such as size, debt to capital, liquidity etc.?

Yes ☐ No ☐

c. Do you have preferences with respect to various sponsors (for example, would you prefer sponsors who are utility companies)?

Yes ☐ No ☐

E. Loan Type Preference (Construction or Permanent Loan)

1. Did your loan cover both the construction period and the operation period of the project?

Yes ☐ No ☐

2. Would you prefer short-term bridge loans (for a period of a few years) only during the construction period?

Yes ☐ No ☐

3. Do you prefer longer term project finance loans (7 to 30 years) only during the operation period or during the construction period of a project?

F. Other Related Project Finance Experience

1. Have you completed loans for similar projects in other industries such as oil and gas, mining or real estate?

Yes ☐ No ☐

a. Did these loans in other sectors cover only the construction period, only the operation period, or both the construction and the operation period?

b. What was the tenor of the loan in years?

c. What was the size of the loan?

d. What suggestions would you have for the sponsor to improve the process for the loans in other sectors?

II. Loan Documents and Process for Borrowing During Construction

CARICOM would like to know your thoughts about the process for requesting loan approval so that the process may be expedited for both your bank and the alternative energy developers in future transactions:

A. Required documents

1. Which of the following documents did you require in completing the transaction?
   a. Term sheet for loan ☐
   b. Loan Agreement Document ☐
   c. Feasibility Study ☐
   d. Purchased Power Agreement ☐
   e. Annual Report of Sponsor ☐
   f. Financial Model ☐
   g. Plant Permits ☐
   h. Guarantee documents ☐
   i. Other documents ☐

2. Can you describe the loan agreement?

   a. What was the length of the loan document (about how many pages)?

   b. What items were the major sections in the table of contents?

3. In the future transactions, how early in the process should the sponsor contact you about the loan?

____
____
____

4. How long did the loan process take after the application was made?

____
____
____

5. What could have been done to make the process more efficient?

____
____
____

B. Sponsor Support During Construction

1. Did the sponsor of the project agree to fund contingencies during the constriction period for possible construction over-runs and construction delays (the sponsor rather than the bank pays for over-runs and added interest caused by delays) ?

Yes ☐ No ☐

____
____
____

   a. If the project had construction cost-over-runs, how would they have been funded (money from sponsors, the bank, or both)?

   ____
   ____
   ____

   b. If the project had delays in completion, how was the additional interest during construction funded?

   ____
   ____
   ____

2. What arrangement would you require in the future for covering the contingencies during the constriction period for possible construction over-runs, construction delays and plant performance (for example, would you require the sponsor or the contractor to cover all contingencies)?

____
____
____

C. Monitoring of Loan Draws During Construction and Sponsor Credit

1. Do you approve or monitor the borrowings made by a developer to pay for construction after the loan commitment was established?

Yes ☐ No ☐

____
____
____

a. Is the timing of the borrowing pre-arranged from the construction budget?

Yes ☐ No ☐

b. Did you hire consultants or independent engineers to monitor or approve the construction process?

Yes ☐ No ☐

2. How important is the credit quality of the sponsor when you make loans (e.g. the ability of the sponsor to fund construction cost over-runs)?

D. Construction Contracts

1. Did you require the developer to secure a fixed price "turnkey" Engineering Procurement and Construction (EPC) contract, in which the contractor rather than the developer accepts the risk of construction problems such as a delay or increased costs?

Yes ☐ No ☐

2. In making future loans, would you require that sponsors enter into EPC contracts with construction companies?

Yes ☐ No ☐

a. How would the presence of a turnkey or EPC contract affect your loan process?

b. If there was a turnkey contract, did you require liquidated damages, bonding or other insurance to make sure the contractor could fulfill the contract obligations?

Yes ☐ No ☐

c. How would you review the credit quality of the EPC contractor or equipment supplier?

E. Completion Tests

1. Was there a completion test for the project that defined the date at which the financial close occurs (when the construction loan stops and the permanent loan begins)?

   a. Could you describe how the completion test worked (e.g. three continual months of operation)?

   b. Did you change anything in the completion test that was originally proposed by the sponsor?

   Yes ☐ No ☐

   c. Do you have suggestions for more effective completion tests in future transactions?

III. The Underwriting Process

CARICOM is interested in your underwriting process so that developers can understand which risks are most important to you and so that the developer can attempt to the mitigate risks before presenting you with loan proposals.

A. Credit Risks

1. In analyzing credit, what were the most important risks that were evaluated?

2. Which of the following risks were most important to you in making the loan?

   a. Resource risk (wind speeds, river flows, etc.) Yes ☐ No ☐

b. Construction cost of plant (construction cost over-runs, construction delays, plant performance).

Yes ☐ No ☐

c. Technological risk of plant not operating as planned (e.g. problems with wind turbine blades).

Yes ☐ No ☐

d. Risks associated with PPA (e.g. credit problems of the utility company or regulatory out provisions).

Yes ☐ No ☐

e. Operations and maintenance expense risk. Yes ☐ No ☐

f. Tax risk (that tax holidays will expire). Yes ☐ No ☐

g. Currency risk from the denomination of the PPA (if the PPA is in USD and the tariffs are in local currency). Yes ☐ No ☐

3. How important was the guarantee or other credit support in the underwriting process?

B. PPA Underwriting

1. What were your underwriting requirements for the PPA?

a. Did the PPA have to be longer than the tenor of loan by a certain number of years? Yes ☐ No ☐

b. Did you allow any out clauses in the PPA? Yes ☐ No ☐

c. Did you require the project developer to make any changes in the PPA? Yes ☐ No ☐

d. Did you require that the currency of base prices in the PPA (e.g. USD/MWH) and inflation indexing provisions for prices in the PPA (e.g. the US GDP deflator) be in the same currency as the loan? Yes ☐ No ☐

e. How important was/is the credit quality of the utility company off-taker that signs the PPA?

2. What provisions would you like to see in a future PPA contract?

C. Risk Scoring

1. Did you classify the loan with a score into a risk category? Yes ☐ No ☐

a. What was the category of the project finance debt?

b. How many risk categories do you have for this type of loan?

c. In general, how did you come up with the score?

d. Was the scoring done in a credit committee? Yes ☐ No ☐

e. How did the loan guarantee affect the credit score?

f. What could have been done to improve the risk rating of the debt?

g. What would have made the risk rating worse?

D. Independent Engineers and Consultants

1. Did you hire independent engineers to review the construction budget, feasibility study, or any other aspects of the project?

   Yes ☐ No ☐

   a. What was the cost for the independent review?

   b. Who paid for the independent engineer (e.g. the sponsor)?

   c. Will an independent engineer or consultant continue to monitor the project in the operation phase? Yes ☐ No ☐

2. Did you use internal staff at the bank to review the construction budget, feasibility study or any other aspects of the project?

   Yes ☐ No ☐

IV. Loan Pricing

In the next set of questions, CARICOM would like to ask you a few questions about the pricing of loans. We understand that pricing is market-driven and changes with market conditions, but we would like to provide developers with a general sense of the interest rates, credit spreads and fees they can expect on a project finance loan:

A. Fixed and Floating Rates

1. Was the interest rate on your loan fixed rate or variable rate?

a. Do you have a preference for fixed or variable rate?

b. If the loan is variable rate, would you use LIBOR as the basis for the interest rate?

Yes ☐ No ☐

c. If the loan is fixed rate, what would be the basis for the rate (e.g. U.S. treasury yields or swap rates)?

d. Did you consider variable rate interest for the construction period and fixed rate for the operation period?

Yes ☐ No ☐

e. Did you have any pre-payment penalties for paying off the loan earlier than scheduled?

Yes ☐ No ☐

f. How would the interest rate have differed if you used a different currency for the loan?

g. Could you have offered an interest rate swap to convert the loan from variable rate to fixed rate?

Yes ☐ No ☐

B. Credit Spreads

1. Can you provide the credit spread of the loan (e.g. in basis points above LIBOR)

a. How did you measure the credit spread (e.g. basis points above LIBOR, basis points above U.S. treasuries yields, etc.)?

b. How would the credit spread have differed if there was no guarantee (how much higher would the credit spread have been)?

c. Was the credit spread the same during the construction period and the operating period, or is the spread higher during construction?

d. Did the sponsor provide a suggested credit spread or interest rate in the loan documents? Yes ☐ No ☐

C. Fees

1. What were the fees you charged for the transaction?

a. Was there a commitment fee on the full amount of the potential loan?

Yes ☐ No ☐

b. What was the basis for the fee?

1.) When were the fees payable (e.g. at commercial operation)?

c. Were there other fees such as underwriting fees? Yes ☐ No ☐

D. Reserves

1. How much capital did you reserve for the loan (as a percent of the loan)?

a. What could have allowed you to reserve less capital?

b. What would have required you to reserve more capital?

V. Loan Size, Syndication and Currency Denomination

In the next set of questions CARICOM would like ask you a few questions about the size of loans and currency denomination of loans for which alternative energy developments can qualify. We will use your responses to give sponsors a reasonable guideline about the size of a loan they can expect and the currency denomination of the loan.

A. Loan Size

1. What was the size of the project finance loan?

2. What was the size of the project finance loan compared to the total amount of money raised for the asset?

3. Was the loan size the same as the size initially proposed by the project sponsor?

Yes ☐ No ☐

4. In general, how would the size of a project finance loan of this type be established?

a. Does the amount of collateral have a significant effect on loan size (for example, if the loan must have 200% coverage of the asset cost as collateral, the maximum loan size would be 50% of the project cost)?

Yes ☐ No ☐

b. Did the debt service coverage ratio play a major role in determining the size of the loan?

Yes ☐ No ☐

1.) How do you define the formula for the debt service coverage ratio (e.g. do you allow cash reserves in the debt service reserve to be included in cash available for debt service)?

2.) Would you use the average debt service coverage ratio over the life of the loan, the minimum debt service coverage ratio, or some other coverage ratio in determining a reasonable debt size?

c. Does the debt to capital ratio have an important role in determining the size of the loan (for example, is the maximum debt to capital at the closing date 70%)?

Yes ☐ No ☐

B. Loan Syndication

1. How large a loan could your institution have accepted without syndication?

2. Do you form loan syndicates for a project finance loan? Yes ☐ No ☐

   a. How large a loan do you think could be made in a syndicate?

   b. What banks would typically be in the syndicate?

   c. Do smaller banks rely on your underwriting in participating in syndicated loans?

   Yes ☐ No ☐

d. Would you want to be the agent bank if a syndicate was formed?

Yes ☐ No ☐

C. Loan Currency

1. What currency was used in the loan (USD, Euro, Local)?

a. Did you consider a different currency for the construction loan and the permanent loan?

Yes ☐ No ☐

b. Do you have a preference as to the currency of the loan? Yes ☐ No ☐

1.) Why did you have a preference (for example, are your deposits primarily in one currency)?

2.) Would it have been possible for you to lend in another currency?

Yes ☐ No ☐

c. Did the sponsor have a preference as to the currency of the loan?

Yes ☐ No ☐

d. Did the escalation provisions (e.g. escalation tied to Consumer price index in the U.S.) in the PPA and the pricing in the PPA (e.g. energy charges in USD) affect the currency of the loan?

Yes ☐ No ☐

VI. Debt Repayment Structure / Collateral/Debt Service Reserves

A. Loan Tenor

1. What was the loan tenor in years (beginning at the commercial operation date)?

   a. Was this the loan tenor proposed by the developer? Yes ☐ No ☐

   b. Is there a maximum loan tenor that you are able accept? Yes ☐ No ☐

B. Grace Period

1. Did the loan you made include a grace period after commercial operation that allowed a period for which there is no debt re-payment? Yes ☐ No ☐

   a. Was the grace period for interest payments or debt re-payments?

   b. How long was the grace period in months?

   c. If a grace period was not part of the transaction, would you have considered a grace period?

C. Collateral

1. What was included in the collateral package for the loan?

a. The entire plant? Yes ☐ No ☐
b. The PPA with the utility company Yes ☐ No ☐
c. Licenses Yes ☐ No ☐
d. Other

____
____
____

D. Covenants

1. What covenants were included in the loan?

____
____
____

a. Was there a restriction on dividends if a certain level of debt service coverage ratio was not met?

Yes ☐ No ☐

____
____
____

1.) What was the level of the debt service coverage ratio in the dividend restriction?

____
____
____

2.) If dividends were restricted, did the loan have to be pre-paid earlier?

Yes ☐ No ☐

____
____
____

3.) Were there covenants on the issuance of additional debt?

Yes ☐ No ☐

____
____
____

4.) What were the affirmative covenants?

____
____
____

E. Debt Service Reserve

1. Was a debt service reserve required for the project? Yes ☐ No ☐

____
____
____

2. Did the debt service reserve have to be held at your bank? Yes ☐ No ☐

3. How much was the debt service reserve in relation to the size of debt service (e.g. six months)?

4. How did you determine the amount of the debt service reserve?

5. How important was the debt service reserve in the overall loan process?

6. How would your debt service reserve requirements change in the future?

F. Guarantees and Credit Support

1. Did the loan transaction that you completed include a guarantee?

   Yes ☐ No ☐

   a. Could you describe the nature of the guarantee (for example, was it a government guarantee)?

   b. Could you have completed the transaction without a loan guarantee?

   Yes ☐ No ☐

2. Would you do a prospective transaction without a guarantee? Yes ☐ No ☐

3. Would a guarantee from the Caribbean Development Bank, the IADB, or other development banks be adequate?

   Yes ☐ No ☐

4. Would a guarantee from an export agency such as the US EXIM Bank be adequate even if it did not cover the entire loan?

Yes ☐ No ☐

5. Does the guarantee have to cover the entire amount of the loan (if not, how much would be acceptable)?

Yes ☐ No ☐

6. If there is a guarantee, does most of the due diligence and credit analysis involve evaluation of the guarantee (and the guarantor) instead of the project itself?

7. Do you have any suggestions for CARICOM with respect to the type of guarantees that should be encouraged with various government agencies?

ANNEX II - Utility Survey

Electric Utility Production Cost Simulation for Renewable Energy Technology Projects

A Survey of Caribbean Utilities

July 22, 2003

Dear Colleague,

The CARICOM Secretariat is interested in your assistance in obtaining data for economic analysis of renewable energy projects (wind farms, solar photovoltaics, solar water heaters, hydro plants, biomass plants and geothermal plants).[37] The CARICOM Secretariat is charged with identifying policy, financing, capacity, and awareness barriers preventing increased use of the Caribbean's substantial renewable energy resources. This involves working with renewable energy project developers, financial institutions, government agencies, utilities, and other organizations in an effort to improve regional capabilities to assess project economics and to finance renewable energy projects. Thirty-eight (38) renewable energy project sponsors have identified 21 potential projects, encompassing a total investment of nearly US$260 million.

Information gathered through surveys of utilities and other stakeholders in the region can help make development and financing of RET projects more practical and more efficient. That information helps define commercial viability for developers, and lets utilities evaluate accurately whether and how they can benefit from the use of renewable energy resources. Information that can be provided only by the region's electric utilities is vital to this process. The utilities are also potential purchasers of the output of economic renewable energy technology projects in the region. The utility companies to whom this survey has been distributed are listed in Appendix 1.

High quality information from utilities impels developers and financial institutions to concentrate their efforts on realistic, economic projects that benefit both local electric utilities and energy consumers. Information from the survey responses will be used to build comprehensive analyses of the potential benefits and costs of renewable energy projects. As part of this investigation the CARICOM Secretariat will also evaluate their effects on consumers' rates, financial institutions' lending, and utility companies. A central component of the planned analysis is estimating the investment and

[37] The Caribbean Renewable Energy Development Programme (CREDP) was developed by the UNDP and the Global Environmental Facility and is managed by the CARICOM Secretariat.

operating costs that your Company would avoid if it took electricity produced by a renewable energy project. The avoided cost analysis will, in large part, be completed

using data from this survey and software tools of our consultants, Adica Consulting. The software includes: a chronological production cost simulation model, a project finance model, and a rate impact model.

Benefits to Utility Companies of Providing High Quality Data

Although the data we are requesting is comprehensive, we believe the benefits from providing the data far outweigh any costs of completing the survey. With analyses based on high quality data, you will be able to fully evaluate whether renewable technologies make sense for your Company. The analyses can assure that developers and financiers do not expend your time and resources, or their energies, on projects that do not make economic sense. CARICOM will provide your company with a comprehensive set of results of the avoided cost analysis, the project finance analysis and the rate impact analysis for your company. In addition, the software -- as well as template PPA and loan documents being developed as part of the project – can be made available to participating utility companies.

Organization of the Survey

To facilitate completion of the survey, it has been divided into easily separated segments that may be distributed among the pertinent company departments. The opening sections are general and financial. The third and fourth sections deal with technical issues and would best be completed by technical professionals in systems planning and operations. The final section addresses siting, taxes and other issues.

We understand that you may not complete all of the data inquiries, but we would appreciate as comprehensive a response as possible. If you have questions about any of the questions or data requests, please feel free to contact Adica Consulting at the telephone number or e-mail address below. You may also complete the survey in stages and provide them to us as they are finished. We would be pleased to receive complete responses by **15 August 2003**.

Confidentiality

We will work with you to identify data requiring special treatment and to assure appropriate treatment of confidential information provided in response to this survey.

Contacts

Inquiries about the questionnaires can be directed to Mr. Ed Bodmer or Ms. Nora Hussar at Adica Consulting. The contact information is:

Edward Bodmer
Nora Hussar
Adica Consulting, LLC

Tel: +001 630 571 2480
Fax: +001 630 571 2481
ebodmer@adica.com
nhussar@adica.com

Thank you for your participation.

Sincerely,

Roland R. Clarke, Ph.D.
Project Manager
Caribbean Renewable Energy Development Project
CARICOM Secretariat
rclarke@caricom.org
http://dolphin.upenn.edu/~clarker
Tel: 0011 592 226 9281 ext. 2631

ADICA CONSULTING

CARICOM RENEWABLE ENERGY UTILITY SURVEY

"Realistic analysis of information that can be provided only by our region's electric utilities are vital to CARICOM's efforts to facilitate the development of economic renewable energy resources in the Caribbean."

Dr. Roland Clarke,
Project Director, CREDP
CARICOM

Part 1. General Questions

2. We are interested in having a constructive dialogue with your company to assist our analysis of the economic and financial viability of renewable energy projects. Please provide contact information for individuals knowledgeable in the following areas for that purpose:

a. General Contact
- *i.* Name ______________________
- *ii.* Phone Number ______________________
- *iii.* E-mail ______________________

b. Technical Contact for Load Data
- *i.* Name ______________________
- *ii.* Phone Number ______________________
- *iii.* E-mail ______________________

c. Technical Contact for Plant Operations Data
- *i.* Name ______________________
- *ii.* Phone Number ______________________
- *iii.* E-mail ______________________

d. Contact for Siting, Permitting and Other Development Issues
- *i.* Name ______________________
- *ii.* Phone Number ______________________
- *iii.* E-mail ______________________

e. Contact for Tax Issues
- *i.* Name ______________________
- *ii.* Phone Number ______________________
- *iii.* E-mail ______________________

Part 2. Purchased Power Agreements and Avoided Cost Calculations

3. Do the utility laws in your country prohibit your company from signing a purchased power agreement with a non-utility company in the business of developing and constructing renewable energy technology projects?

   Yes ☐ No ☐

4. We would like to provide potential developers with information on the applicable law in each country respecting delivery of power to the grid. Please describe briefly the current laws or regulations governing the generation, transmission, and distribution of electricity applicable to your company. If possible, please provide a copy of the regulations that pertain to purchased power agreements or a source from which we can obtain the law and/or regulations.

   ____

   ____

   ____

   ____

   ____

5. Has your company signed purchased power agreements with independent generation companies?

   Yes ☐ No ☐

6. If your Company has signed purchased power agreements, could you provide a (complete or redacted) copy of such an agreement for each of the generation technologies used?

   We have attached a copy of our PPA's? Yes ☐ No ☐

7. Has your company undertaken renewable energy projects of its own?

   Yes ☐ No ☐

8. Has your company computed its avoided cost, possibly to evaluate alternative generation technologies?

Yes ☐ No ☐

9. If the answer to the above question is yes, could you provide a copy of the avoided cost study?

We have attached a copy of our avoided costs study. Yes ☐ No ☐

10. What arrangement with your company is the most realistic option for developing renewable energy technologies? Choose the response that best describes the circumstances of your utility.

a. The utility law does not allow generation from independent generation entities, which means the utility company must develop (finance and construct) the projects.
b. The utility law does not allow generation from independent generation sources, but it may be possible to change the law to allow exemptions for renewable technologies.
c. The utility law allows independent generation and we would be willing to work with developers on a power purchase agreement.

Enter the letter of the best description.

Additional Comments:____

____

11. In developing purchased power agreements with independent power producers, which of the following responses best describes the process that would be used for your company?

a. The purchased power agreement would be negotiated between the utility company and the developer without any need for approval from regulators or other government agencies.
b. The purchased power agreement would be negotiated between the utility company and the developer, but the agreement must be approved by regulatory agencies.

c. Regulatory agencies and/or other government agencies would be directly involved in negotiating purchased power agreements.

Enter the letter of the best description.

Additional Comments:____

12. Which of the following responses best describes the process for determining price terms for a purchased power agreement at your company?

a. We would apply a tariff that changes from year to year and is derived from calculations of our avoided cost.
b. We would negotiate a long-term fixed price that is derived from estimated avoided cost.
c. We would negotiate prices from a variety of factors – not exclusively avoided cost.
d. We do not know at this time the basis upon which we would develop prices in a purchased power agreement.

Enter the letter of the best description.

Additional Comments:____

13. Which of the following responses best describes your company's policy with respect to its calculation of avoided cost:

a. We compute the cost of fuel that would be avoided if we purchased power from another source.
b. We compute the cost of fuel plus variable operation and maintenance costs that could be avoided if we purchased power from another source.
c. We compute the cost of building a new plant that we could avoid if we purchased from another source.
d. We include line losses on the transmission and distribution system in the avoided cost calculation.
e. We have not computed avoided cost, and we do not have policies on how to compute avoided costs.

Enter the letter <u>or</u> <u>letters</u> of <u>all</u> the responses that apply.

Additional Comments:____

14. Please provide details on the types of analysis that your Company would require to justify investing in a renewable technology project.

____

____

____

____

15. Please comment on the type of analysis your Company would require to justify signing a purchased power agreement with the developer of a renewable energy project.

____

____

____

____

16. Please describe as specifically as you can the principal concerns your utility would have in signing a purchased power agreement with a "non-utility" generator. For example, depending on their particular circumstances, other utility companies have voiced concerns about grid stability, interconnection provisions, financial viability of the supplier, reliability of the power source, or regulatory problems.

____

____

____

____

ADICA CONSULTING

Part 3. Load Data and Capacity Expansion Plans

17. The model we use to compute production costs simulates hour-by-hour operation. Inputs include the hourly loads for a non-leap year (8,760 data points, each representing one hour of load data). A realistic simulation requires at least one year of hourly load data (2002). Three years of hourly load data (2002, 2001 and 2000 is preferred. The data should be provided in an *MS* Excel file

    Years of hourly data files provided ___________

We will be analyzing the economics of renewable investments over the life of the investment, which requires a long term forecast of avoided cost. To make that forecast, we need to project increases in peak demand and energy output. Choose the response below that best describes your utility's forecasting practices.

a. Our company makes long-term forecasts, which we have provided in a computer file (or in "hard-copy").
b. Our company makes long-term forecasts. They show a trend of ___% (fill in the annual growth rate in peak demand and energy use).
c. We do not make long term forecasts

Enter the letter or letters of the response(s) that best describes how your company makes long-term forecasts. (If "b" is chosen, fill in the growth rate.

Additional Comments:____

____

18. Please provide copies of your company's projections of its annual load and capacity table and/or your capacity expansion plans.

19. Please describe the analytical model that you use in making capacity expansion decisions (for example, WASP, ELFIN, *OGP*, Screening Analysis or other.)

____
____
____

20. We would like to assure that our analysis is consistent with your capacity expansion modeling. Therefore, if possible, please provide inputs and outputs from your company's capacity expansion analysis (for example, inputs and outputs from the WASP IV model).

21. Which of the following responses best describes your company's criteria for building new capacity:

a. We use a reserve margin criterion of ____%.
b. We use a loss of load probability criterion of ___%.
c. We use other criteria, specifically: ________________________________
____

22. Among the inputs to the avoided cost analysis are the cost of capital and the technical characteristics of the newly constructed plants (such as new slow speed diesel units). If available, please provide your Company's assumptions with respect to the following factors.

a. The capital cost for new diesel or other technology plants (US$/kW basis, without interest during construction)

____

b. The projected operation and maintenance cost (Fixed O&M in US$/kW/Year (2003) and variable O&M cost in US$/MWH)

____

c. Average Net Heat Rates on new units in (BTU/kWh), and Average Heat Rates at different levels of operation

____
____

Part 4. Plant-by-Plant Operating Data

23. ***GENERAL DATA:*** To complete the planned avoided cost and rate impact analyses, we must enter data for each of your generating plants (fossil-fired generation plants, hydro or other technology plants) and for purchases from independent plants. We would like data for each of your plants, including the plant name, the plant type (slow speed diesels, internal combustion, steam plants, combustion turbine plants, hydro plants, etc.), the fuel type (number 2 oil, number 6 oil, etc.), the year the plant was commissioned, and its expected remaining life.

Plant Name	Plant Type	Fuel Type	Summer Capacity	Non-Summer Capacity	Year Built/Expected Remaining Life

24. ***DETAILED PLANT DATA:*** In addition to general data on each plant, we would like to take account of more detailed plant data in our analysis. Please tell us: whether the plants are dual or even multi-fuel; the costs of starting the units; whether the plant is used primarily for base load or peaking purposes, and the plant's carbon emission characteristics and data.

Plant Name	Fuel Switching (Yes/No)	Alternative Fuel Type	Base Load or Peaking	Emission Factors for CO_2, Nox and SO_2 per MWH	Ramp Rate and Start-up Cost

25. ***HEAT RATE DATA:*** For each of the above plants that are diesel, steam turbine, combustion turbine, or internal combustion, we will use data on the plant's heat rate, variable operation and maintenance costs, scheduled and unscheduled maintenance, fuel cost, and emissions. We also would like to incorporate the effects of different levels of plant operation on avoided cost.

For example, if a plant is operating at its minimum operating level, it may have very low marginal cost. To model a heat rate curve, we would like to enter data on the heat rate at four (4) operating blocks of the plant.

In completing the table below, we recognize that you may define heat rate curves using incremental heat rates or heat rate coefficients, instead of the block by block average heat rates in the table below. If you use a different method to define heat rate curves, please modify the titles of the table and fill in the relevant data.

Plant Name	Average Heat Rate (BTU/kWh)	Block 1 (1st 25% of capacity) Heat Rate (BTU/kWh)	Block 2 (2nd 25% of capacity) Heat Rate (BTU/kWh)	Block 3 (3rd 25% of capacity) Heat Rate (BTU/kWh)	Block 4 (4th 25% of capacity) Heat Rate (BTU/kWh)

26. ***OPERATION AND MAINTENANCE COST DATA:*** We will be taking account of the variable costs of operating and maintaining the plants in the analysis, as well as the cost of fuel. The table below requests plant by plant data on: (a) total O&M costs, including overhead, for a recent 12-month period; (b) projected fixed O&M US$/kW-Month; (c) projected variable O&M US$/MWH; and (d) historical capacity factor of the plant (generation-hours in year/capacity).

As a preliminary matter, please describe how you have separated costs into fixed and variable components:

____

____

____

____

Plant Name	Total O&M/yr, incl. Overhead (US$)	Projected Variable O&M/MWH	Projected Fixed O&M/kW-Month	Actual Capacity Factor for 12 Month Period	Contract with Supplier for O&M (Yes/No)

27. ***SCHEDULED AND UNSCHEDULED MAINTENANCE:*** In the avoided cost analysis, we will use projected scheduled and unscheduled maintenance outages on a plant by plant basis. Unscheduled maintenance is entered as a percentage of time, and scheduled maintenance can be entered either in terms of start and end dates or as a percentage of plant capacity for each month. Please fill in the table below for: (a) historic availability factor (total hours available/total hours in the year); (b) projected forced outage rate (unscheduled outage time/total time plant is not on unscheduled maintenance); and (c) scheduled maintenance per month (percentage of capacity or start and end date per month).

Plant Name	Availability Factor for Recent 12 Month Period (Percent)	Projected Forced Outage Rate	Months in which Scheduled Outages Occur	Percent of Month Plant is Unavailable for Unscheduled Maintenance	Start and End Date of Scheduled Maintenance

28. ***FUEL COST DATA:*** While we will develop independent forecasts of fuel prices, the fuel cost delivered to the plant also includes different transport costs. To evaluate fuel costs, we are interested in the actual fuel costs (and transportation costs), as well as projected fuel prices.

Plant Name	Fuel Cost/MMBTU for Recent 12 Month Period	Transportation Component of Fuel Cost/MMBTU for Recent 12 Month Period	Non Transportation Cost/MMBTU (Commodity Cost) for Recent 12 Month Period	Projected Transportation Cost/MMBTU of Fuel	Projected Commodity Cost of Fuel ($/MMBTU)

29. ***HYDRO PLANT DATA:*** The final technical data requested are the energy generation and storage characteristics of any hydro power plants. We need these data because the operation of hydro plants can affect the operation of other plants on a utility system and the total costs experienced by the system. We are requesting hydro data on a month-by-month basis because hydro generation can be affected by seasonal weather patterns. Since the annual generation from hydro plants can vary significantly, we are also requesting the maximum and minimum amounts of generation in the past ten years.

	Hydro Capacity (MW)	Monthly Hydro Generation (MWH/Mo)	Maximum Monthly Generation in 10 Year Period (MWH/Mo)	Minimum Monthly Generation in 10 Year Period (MWH/Mo)	Plant type (run of river or storage). If storage, give daily or monthly constraints
First Hydro Plant Name:					
January					
February					
March					
April					
May					
June					
July					
August					
September					
October					
November					
December					
Second Hydro Plant Name:					
January					
February					
March					
April					
May					
June					
July					
August					
September					
October					
November					

December					
Third Hydro Plant Name:					
January					
February					
March					
April					
May					
June					
July					
August					
September					
October					
November					
December					

Part 5. Siting, Taxes and T&D Losses

30. Since utility companies routinely construct distribution, transmission and generation facilities, you are in a unique position to explain the local processes for siting, permitting, and securing regulatory approvals for a renewable energy project. We request information on the following issues:

    a. Plant Permitting Agencies:

    ____

    ____

    ____

    b. Plant Siting Approvals:

    ____

    ____

    ____

    c. Required Environmental Approvals:

    ____

    ____

31. In evaluating the total costs of constructing and operating a renewable plant, tax issues and import duties can have an important impact on the cost/benefit analysis. We are asking for information on the following tax issues:

    a. General income tax rate on corporations: _______%

    b. Property tax rate on electric generation: _______%

    c. Property tax rate on land associated with generation: _______%

    d. Sales taxes or fees on generation equipment: _______%

    e. Tax rate on electricity sold by an IPP to utility: _______%

    f. Import duties on electricity generation equipment _______%

    g. Capital Allowance/Tax Depreciation Method:

        i. Straight Line YES NO

ii. Accelerated Method: ______________________________

h. Tax Depreciation Life for Different Types of Projects

i. Wind Farms: ______ Years

ii. Solar: ______ Years

iii. Hydro: ______ Years

iv. Biomass: ______ Years

v. Geothermal: ______ Years

i. Describe other tax issues that you believe could significantly affect the economics of renewable energy technology projects.

____

____

____

32. Certain "off grid" projects such as solar water heaters and photovoltaic systems (PV's) would allow your company to avoid transmission and distribution losses as well as other generation related costs. Therefore, we are interested in your Company's estimated loss parameters:

a. Transmission loss rate: _____%
b. Distribution losses (technical): _____%
c. Distribution losses (commercial): _____%

33. Certain projects could eliminate the need to make grid extensions. To evaluate these cases, we will require data on the cost of extending a distribution line and on allocating the costs of the distribution line. Please describe how your company recovers the costs of line extensions.

____

____

____

____

APPENDIX 1

COUNTRY	UTILITY COMPANY
Antigua and Barbuda	Antigua Public Utilities Authority
The Bahamas	Bahamas Electricity Corporation

ADICA CONSULTING

Barbados	The Barbados Light & Power Company Ltd.
Belize	Belize Electricity Limited
British Virgin Islands	B.V.I. Electricity Corporation
Dominica	Dominica Electricity Services Ltd.
Grenada	Grenada Electricity Services Ltd.
Guyana	Guyana Power & Light, Inc.
Jamaica	Jamaica Public Service Co., Ltd.
Montserrat	Montserrat Electricity Services Limited
St. Kitts and Nevis	Electricity Department, Ministry Communications, Works, & Public Utilities
St. Lucia	St. Lucia Electricity Services Ltd.
St. Vincent and the Grenadines	St. Vincent Electricity Services Ltd.
Suriname	Suriname Power Company
Trinidad & Tobago	Trinidad & Tobago Electricity Commission
Turks and Caicos Islands	Turks & Caicos Utilities Ltd.

ADICA CONSULTING

ANNEX III – Project Finance Background

Project Financing Basics[38]

Adequate financing is essential to successful, broad deployment of renewable energy technology (RET) facilities. While public financial resources can be useful, especially at the early stages of a project, to move beyond limited demonstration projects, the greater financing resources of the private sector must be tapped. This section of the report examines some of the problems, limitations, and strategies relevant to private sector financing of RET projects.

Unlike governmental or multilateral financial institutions, commercial financiers do not have a so-called double bottom-line perspective, where a public good (*e.g.*, environmental or conservation benefits) is considered a supplement to economic profit in evaluating a deal. Consequently, a pragmatic focus on the business fundamentals of project finance is necessary to financing a wide dissemination of RET projects. By collecting and sharing the best practices of successful financings in the Caribbean region and elsewhere, the financing strategies and capabilities of the entire region's RET developers can be enhanced. In addition, acquainting project developers with the processes of commercial financing can enable them to pursue private sector financing more effectively.

The Project Financing Structure

Typically, a project finance structure involves both debt and equity. Referring particularly to the loan portion of such a structure, project financing is best suited to developments where the development's output or product can be sold and used to service that debt component. Since the revenue flow from the project is the critical factor, this financing structure can be used for a wide variety of developments, including energy production projects. In a project financing structure, highly leveraged arrangements are viewed favorably from the perspective of developers. Since debt is usually lower in cost than equity, it is relatively more attractive to the developer. Project financing arrangements have incorporated levels of debt financing as high as 60-70%, with reports of unusual cases financed with as much as 90% debt. Companies are increasingly using project finance to fund and manage developments requiring large capital expenditures.

[38] The discussion in this section borrows heavily from the results of research on project financing reported in Murphy, Brokaw, Boyle, "Transitioning to Private-Sector Financing: Characteristics of Success" (Transitioning), March 2002 • NREL/MP-720-31192 and the report is not cited at every possible instance. (The full NREL report is accessible at http://www.nrel.gov/docs/gen/fy02/31392.pdf (accessed Nov 8, 2003).

The project financing model is a favored capital accumulation vehicle in large projects like electricity generating plant developments. Many of the merchant plants constructed in recent years have been supported through project financing. (Significant non-energy developments using the project financing structure include the $16 billion Channel Tunnel, and a $1 billion BP oil field production venture.) In the United States, a demand for project financing was created by the development incentives of the Public Utility Regulatory Policy Act (PURPA) of 1978, which mandated utility purchases of the output of certain energy efficient production facilities. Project finance was the finance structure vehicle of choice for the resulting power plant developments of the late 1970s.

Generally, project financing arrangements are more suitable for larger projects, because the task of negotiating the various aspects of such deals –financing arrangements, construction contracts, operations and maintenance, other agreements -- is expensive. Moreover, making all the necessary arrangements is roughly as costly and time-consuming for small projects as it is for large ones. Generally, effective projects are large in the $100 million and above range. Even on smaller projects, the effort to raise, hypothetically, $10 million would be about the same as the amount of work required to raise $25 million.

A characteristic that project financing shares with all other loan arrangements is that the level of risk perceived by the lender affects both the availability and the cost of financing. Because lenders must be confident that a project's output (and the resulting revenues) can service its debt, project financing is most easily obtained where there is a mature, proven technology already familiar to debt investors operating in a known market. Newer technologies, without a proven track record, have higher perceived risk levels. Even where similar RET projects have been successful on pilot or small scale, an untested commercial scale-up may nonetheless be perceived as risky. Caribbean RET projects will most often face these unfavorable perceptions. The recommended strategic approach to this problem is a proactive program, by the developer, to educate potential lenders about the reliability and commercial viability of the pertinent renewable energy technology and about the project's relevant markets.

Project finance does, however, have characteristics that distinguish it from more traditional financing arrangements. The differences begin with the developer/borrower. Even where there is an established entity backing a project, that company ("sponsor" or "parent") sets up a separate legal entity, which will own the single-use production assets for which financing is sought. The separate entity is formed specifically to develop, finance, and then manage the project. The project (the separate legal entity) is financed with large amounts of debt. This legal structure insulates the parent firm from the risks of developing the project, and it gives creditors recourse only to the project's assets and cash flow, but not against the parent. Such arrangements are described as "non-recourse" as to the parent. Consequently, the creditors share in the risk of the project, making project finance lenders resemble like equity investors as much as traditional lenders. While a parent may provide some assurances at the beginning of a project (limited recourse), the parent will insulate itself completely as quickly as possible. Certainly, once a project is

commercially operational, there will be no recourse to the parent. From the parent's perspective, the financing of the project is off-balance sheet, meaning that none of the debt is recorded on the parent company's books.

This seemingly one-sided arrangement is sustainable because of the nature of the assets that are covered in project financing arrangements. Projects are categorized as either stock-type or flow-type. Stock-type projects are involved in the extraction of resources (minerals, oil) that are sold to produce a revenue stream. Projects where the use of the assets provides a cash flow, with which creditors and investors are compensated, are called flow-type projects. Electricity production plants fall in this category.

Despite the nonrecourse nature of project borrowing, the project entities are usually highly leveraged, because the assets and cash flows are predictable and long-lived. For developments that are attractive to financial institutions, the project assets are not subject to quick obsolescence and are reasonably expected to provide predictable cash flows to the project's lenders. Often there is a contract to take the project's output (*e.g.*, a PPA) that assures the cash flow. Given these characteristics, the acceptable leverage ratios for the entity can be significantly higher than for other entities.

Additionally, the lower probability of default (because of an assured revenue stream) and the project finance lender's usual contractual right to take over the revenue producing operation in case of default combine to enable the use of high leverage. The high interest payments themselves can be used for tax advantages where interest is an allowed business expense. The single asset special entity organization makes it easier for creditors to evaluate the project, to monitor construction, and to track cash flows. This transparency can increase lender comfort and decrease the cost of capital. Separation of the operation from a larger enterprise may also facilitate access to special public sector benefits and incentives. Properly structured project finance arrangements can be advantageous for both developer and financier.

The most time-consuming and expensive portion of project finance is negotiating and putting in place the various pieces of the financial arrangement. That process is neither swift nor simple and is best approached with a clear and effective strategy for obtaining and implementing financial support.

Commercial Financing Strategies for Developers

In NREL, the authors identify three components of an effective strategy for obtaining commercial financing that have been used by successful RET entrepreneurs. We will use those components as an organizing framework for our discussion, supplementing them with additional strategic elements found useful in the Caribbean financial community.

> *First:* Understand the financial community, and involve them early in the development process;
> *Second:* Strengthen the business fundamentals of the project; and
> *Third:* Focus on and be driven by market considerations.

Importantly, the report notes that acting on only one or two of these strategies is rarely sufficient. To be successful, developers must incorporate all of these components into a disciplined effort to obtain commercial loan financing. Our discussion addresses each of these strategic components in turn, combining the lessons of the more general NREL research with the teachings of the more focused research (targeting the CARICOM region) undertaken as part of this project.

Knowing and Involving the Financial Community

Know the Options. Developers must become acquainted with the full range of financing institutions and financing options, and allow potential lenders to become acquainted with them, their project technologies, and relevant commercial markets. The available financing options often depend principally on the nature of the project, its location, and the stage of development of the business. A particular technology or application of that technology may be the subject of governmental or multilateral assistance programs. Such government, multilateral or public advocacy financing is often based on non-economic factors. Predictably, those assistance programs (especially in the case of governmental programs) are likely to be available only in certain countries or geographic locations. Such programs are also more likely to offer help at the pilot or proving stage of a new technology or application. Commercially viable projects -- our focus -- may have fewer such programs open to them, and commercial financing depends far more on demonstrated economic viability.

Despite private sector financiers' clear focus on the economics, the non-economic factors noted above also affect the commercial financing options available to developers. Each category of financier -- whether venture capitalist, equity partner, government, or commercial lender -- has a preferred area of focus and specific participation requirements. With private investment or commercial lending, the requirements are almost always directly related to the risk of non-recovery of the committed capital and a return on those funds.

Much of the risk perceived by potential financiers corresponds to the stage of development of the project. In the early stages of project development the circumstances that could hinder or preclude recovery are significant and varied. There are technical risks (will the performance match the promise of the technology?), market risks (will the revenue-producing market develop without unanticipated competition?), and business risks (will the management team be adequate to the task?). As the project proceeds through the stages of its development, the number and variety of risks between funding and recovery decreases. Time frames for unfavorable occurrences shorten, more information resolves uncertainties about technology and markets, and management proves itself by moving the project forward. As these factors change, so do the financing requirements. The required level of return for project financing generally decreases and the commonly used financing vehicles change as the project moves closer to commercial operation.

Entrepreneurs need to be keenly aware of where they are in the development and financing process and aware of the requirements for new financing at that stage.[39] Early capital often requires an equity stake in the project, since loan capital may be unavailable when risks are very high. Government grants and financing may be available at early stages of a development, but such assistance can be a double-edged sword. Short-term government incentive and assistance programs that aim to build operational experience and to bring down costs are viewed positively by potential lenders. However, an over-dependence on government contracts, incentives, or support can lead lenders to question whether there is a real market for the technology. If the government-sponsored assistance appears to retard development of commercially viable enterprises or actual market entry, lenders will be cautious. No lender wants to be left holding an uncollectible loan if there is a change in government policy that transfers support to a different technology or that terminates a subsidy. The revenue stream that will repay a loan should be sustainable independently of governmental supports.

Process and Lender's Perspective. It is equally important that developers learn how to approach the financing tasks -- *i.e.*, how to position themselves to obtain commercial funds. Cleverly, it has been said that "obtaining financing is a 'contact sport'." NREL at __. The fundamental truth of that maxim, however, should not be underestimated. Lending is always a matter of comfort for the financier parting with funds. Is the prospective lender comfortable that he will get his money back (with appropriate risk returns), that the party seeking financing is a competent business manager, that the project itself is viable and likely to produce the needed cash flow for timely repayment? The totality of factors contributing to the lender's comfort -- or lack thereof -- ultimately determines whether a loan is granted.

The bases identified in the NREL report for its succinct description of the financing process -- a "contact sport" -- include the following observations.

1. Involving lenders early in (or even before) developing a project builds trust and mutual understanding, a critical foundation for a decision to finance a project.
2. Potential financiers will have time to become knowledgeable about and comfortable with a new technology, as well as with relevant target markets.
3. Building a portfolio of financial contacts facilitates efforts to obtain financing at the construction or later stages of a project.
4. Referrals or recommendations to a lender from its colleagues in the financial community may be the most important endorsement a project or management team can get during the quest for financing.

[39] The focus of this consultancy is commercial loan financing for RET projects. The search for venture capital, equity or technical partners is outside that scope. Although information useful in that context is included in this report, that is not our focus and we discuss it only in passing.

Ideally, the economics of a project will be sufficiently compelling that more subjective factors are unimportant. But, that will not always be the case with RET projects using unfamiliar technologies in nascent markets. When lenders are expanding their loan portfolios into new areas, more may be required to overcome a lender's unease from a lack of experience or familiarity with the technologies, markets, and business operations of RET ventures. In these situations, preliminary contacts that acquaint financial institutions and individual lenders with the developer, educate the lender about a technology, and build confidence in the developer's business acumen can be decisive.

An early relationship between a developer and financing institutions facilitates the developer's task of familiarizing potential lenders with the project's technology and management. Adding a new technology to its portfolio of loans is a big step for a lender. Lenders will justifiably feel uneasy entering markets where they feel inadequately informed about the technology, the character of the market, or applicable regulatory constraints. Early contacts between the developer and potential lenders can provide invaluable knowledge for both lenders and developers. In fact, involving lenders early can save the developer valuable time later. By identifying those financial institutions likely to provide financing, and taking advantage of advice about financing options from lenders that have gained the developers confidence, the developer is advantaged, even as the developer works to educate lenders about its technology and markets

Information asymmetries, where lenders still know significantly less about the technology or market underpinnings of a project than the developer, create a risk concern. The larger the information asymmetries, the larger the perceived risks, and the higher the cost of capital. Developers can address this and other risk concerns through the strategy of early contact and proactive education. Developers should create and use contact opportunities to share information -- about technologies, about markets, and about you, the developer. Public-sector agencies like CARICOM also can play a significant role in early contacts and education and enhance the effect of their own assistance programs. By becoming familiar with the community of financial institutions, raising awareness of renewable energy technologies (even before there are specific projects at hand) and working to coordinate commercial and public funding, governmental and multilateral entities can help develop new sources of financial support for RET projects.

Business Fundamentals

The need to develop balanced organizations to support RET projects is a function of both prudent business practice and the need to reduce the perceived risks of potential lenders. "Uneven" organizations with strong technical skills but weak business skills are unlikely to be favored in the competition for financing. A project with sound business fundamentals and a good techn1ology is often deemed more attractive for financing than a great technology in a flawed management structure.[40]

[40] "[G]reat technologies rarely succeed by themselves. However, great businesses using good technologies usually do succeed — and typically get financed." NREL at ___.

As noted earlier, over-dependence on public-sector financing (even when it advances a technology or a project) can adversely affect the perceptions of potential lenders. If commercial financing is an objective for the project, developers must be careful how and to what extent public or multilateral financing is employed. While public sector assistance may be important in early stages of development, potential investors may perceive it as confirmation of suspicions (possibly based on lack of knowledge) that a project is not economic and cannot succeed without a subsidy.[41] That makes it an unlikely candidate for private sector funds.

Some projects have been built around characteristics that make it easier to secure more governmental support. Since such programs often focus on advancing technologies instead of commercial operations, developers can end up with "uneven" organizations with strong technical skills but little experience or depth on the business side. This well-intentioned imbalance, however, is not attractive to potential lenders and can make attracting financing more difficult.

Like investors, lenders want management teams with business start-up and operations experience. Developer management teams that have taken the time to build potential lenders' trust and confidence in their capabilities are far ahead of late-comers. The NREL report remarks that "Investors commonly say that they would rather invest in a company with an 'A level management team' and a 'B technology' rather than a company with a 'B management team' and an 'A technology.'"

To demonstrate business acumen equal to its technical expertise, the developer must have a solid business plan that outlines the business fundamentals of the project -- business concept, product, technology, business model, competition and other market issues, financials, and plan for profitability or cash flow that will permit timely repayment of the loan. The unusual nature of many RET projects – capital intensity, long lead times, and regulatory hurdles – can complicate the search for financing. In addition to the discussions of business issues, this report addresses that particular need practically, through the inclusion of a useful primer on development of business plans suitable for RET projects (*see*, _____) and the presentation of actual information memoranda for RET projects in the CARICOM pipeline (*see* Volume __).

[41] Most of the public funding available is focused on technology development. The research and development to establish new technologies is often deemed too risky by private investors. Public funds can fill that gap. Where governmental or multilateral funding is available for activities beyond the early stages of technology development, it may be limited and come with well-defined constraints – constraints that usually preclude support through full commercial operation. Consequently, at some point, the project must attract some measure of private financing.

A well-rounded enterprise not only increases the intrinsic value of the business, it lowers the perceived risk, and hence increases its attractiveness to lenders. The customer and the comparison of these benefits with the competition.

Market Focus

It is axiomatic that private financiers – like developers -- need to make money, lest they go out of business. Accordingly, lenders and investors look for indications that a proposed project is market focused -- in its business planning, in its products, and in its operations plan. The remarkable advances made in renewable energy technologies in recent years will overcome the difficulties a RET project faces in the contest for commercial financing. The recent successes of RET projects in delivering competitively priced electricity might do so. Such market performances, with strong justifications for similar expectations in the relevant Caribbean markets, are much more important to lenders. Developers must demonstrate the economic viability of their projects. Market-driven products, not exotic technologies, produce the revenues that assure a lender it will recover its principal and its risk premium.

Renewable energy technology projects often suffer from association with limited markets. In many cases, RET markets must be created or developed. At the same time, RET developers must compete in existing markets where the entrenched suppliers (against whom RET projects must compete) have significant market advantages – especially during the period of market development. Such circumstances raise the bar for RET developers in compiling support information for financing requests. The lack of market performance data and competitive performance history is a difficult problem. Quantitative data and projections are very important, but they are not easily produced in nascent markets with scant public data. This report addresses that problem directly through its collection, analysis, and application of regional market and production data for several types of RET projects.

Even with the information developed for CARICOM in this consultancy project, there are hurdles peculiar to all but the largest RET projects and smaller Caribbean electricity markets. The consequences of inaccuracy in project cost or market performance projections are amplified. Errors in a large market project's analyses are likely to be relatively small (in comparison to the economic foundation for financing). In contrast, the same error in a smaller RET project may (because of the relatively larger size of an error to the project capitalization) have an effect that undermines the economics of the project's financing.

Similarly, market robustness can offset errors in the valuation of a project or relevant market performance, or ameliorate other uncertainties. If a market is sufficiently large, errors in financial projections like projected costs or projected market share, may be inconsequential in the overall context and allow the venture to be viewed positively nonetheless. Extra care in developing and presenting required market and performance

projections and using (to full advantage) the quantitative analyses presented as part of this report can minimize this concern.

Clean energy entrepreneurs face an added challenge in explaining or defining a market that is just emerging. That is especially the case for what have been called "disruptive technologies." Such technologies offer a different value proposition from past or current market offerings. RET projects that attempt to internalize (and reduce) some of the societal costs that current electricity markets often ignore (or pass on to customers in another guise) could easily be perceived as introducing disruptive technologies.

Often new markets must be created and developed, while simultaneously attempting to sell in to existing markets where the entrenched competition is fierce and may have an unfair market advantage, particularly in the short term. The NREL report notes that "Many of the distributed generation developers that were interviewed believe that some utilities use unreasonable terms, excessive costs, and inappropriate delays to either gain utility advantage or impede the market for distributed power." NREL at ___.

Figure 83 Percent Reduction in Price from Renewable

ANNEX IV – Financial Survey Process

Guiding Principles

From previous work performed for the CARICOM Secretariat, one can conclude (a) that bankers are unlikely to reveal the level of detail we desire to questioners from outside banking circles or from outside the region and (b) that the response rate for surveys that require banks to fill out and return questionnaire forms is likely to be very low. After considering several means of contacting financial institutions, the following preference ranking was clear: in-person, telephone, e-mail. Additionally, we gave high priority to contacts with experienced energy sector lenders and to relieving contacts of the burden of written responses to a lengthy questionnaire.

No matter the form of the survey, we identified principles (developed in conservations with Dr. Roland Clarke) that will apply. In all contacts -- interviews, e-mails, or telephone conversations -- our entire team will abide by the following guiding principles:

- The survey or questionnaire must anchor the participant through describing who the interviewer is (CARICOM) and what the objectives of the survey are;

- Brand names recognized by the participant – CARICOM, CARILEC and utility companies (not consulting firms) should be mentioned prominently to encourage cooperation;

- Finding the correct contact person is essential – all references should be carefully noted to update the contact database;

- In general, questions should be guided (e.g. multiple choice) for smaller institutions rather than open-ended – however, interviews with "first-tier" institutions (major regional and those active in the energy sector) should use open-ended questions;

- Scripts should be used, even if the interviewer is expert in the subject, to maintain consistency in collected data;

- When contact is established with a proper respondent, pursue the survey data immediately;

- E-mail surveys will probably not be very effective and will likely be lost;

- In certain areas, interest rates for instance, the questioner should not expect specific data, but expect a range of data; and

- All information gathered should be carefully recorded.

The Survey Process

Given the nature and depth of the information we are attempting to obtain from the major regional banks and from financial institutions with Caribbean energy sector experience, the detailed survey will be used (where possible) for the first-tier subset of financial institutions who have completed project financings. The current contact list, which was developed through the work of CARICOM Secretariat professionals and consultants and our analysis of utility company annual reports, identifies known first-tier institutions, but will be updated as survey results indicate.

First Tier and Second Tier

Our methodology for the survey is based on a two-tier hierarchy that recognizes the special insights that can be provided uniquely by major financial institutions that have made project finance loans. These are the first tier institutions. The lower, second tier consists of all other financial institutions on the contact list.

Survey Documents

Initially, all contacts received an e-mailed letter that explains the CARICOM survey purposes and objectives that is attached. The letter asks for their support, pointing out possible advantages to financial institutions of lending to the sector. This opening communication leaned heavily on the CARICOM brand to prompt the fullest cooperation. The electronic communication was also to include, as attachments, (a) a questionnaire on the lender's alternative energy financing experience, interest, processes, and terms, and (b) a Term Sheet for a (hypothetical) sample project financing arrangement. However, the substantive questionnaires and survey procedures are different for first and second tier institutions. The distinct procedures are discussed separately below. The referenced attachments include: (1) The contact list; (2) the General Questionnaire; (3) the Detailed Questionnaire; and (4) the Questionnaire script. Each of these documents is included in Volume __ of the Final Report.

Process for Second Tier (General Survey)

The second tier institutions receive an electronic copy of the General Questionnaire, a discrete choice questionnaire on alternative energy experience, interest, processes and loan terms. Advance provision of the questionnaire allows respondents to familiarize themselves with the scope of the survey and gather requested information. The Term Sheet can be a vehicle for institutions unfamiliar with project financing to familiarize themselves with it through the sample arrangement. The Term Sheet is also referenced in the questionnaire as the basis for a request for comments. Contacts will be asked to participate through an interview to be arranged in a follow-up call that we will make within a short, designated period. The follow-up call to these institutions will be made by

a junior professional who would immediately verify that the financial institution is new to the energy lending in the region. (If a financial institution is identified as an experienced lender at this point, arrangements are made for an interview that would conform to the procedures for first tier enterprises that are described below.)

Consistent with our interview principles, the interview could occur during the follow-up call if that is convenient for the financial institution contact. Otherwise, an appointment for a telephone interview at a later date would be arranged, and the interview would be conducted as arranged. Appointments will be coordinated so that a senior professional is available for questions by telephone or – if a promising contact consents – joining the call.

Because the General Questionnaire is designed as a discrete choice instrument, and constitutes a ready checklist of data that should be collected, these interviews of second tier financial institutions can be conducted by a junior professional. A script has been developed that will help the interviewer in opening the interview and then anchoring the respondent on the survey's purpose and objectives. The questionnaires themselves will guide the remainder of the interview.

Process for First Tier (Detailed Survey)

First tier institutions receive the Detailed Questionnaire and the sample Term Sheet. They also will be asked to participate in the survey through an arranged interview. In this separate communication, the first tier institutions are reminded that they possess special knowledge and experience, and that we value their insights. They are asked to take part in a more detailed interview that aims to draw on their regional or energy sector lending experience. The Detailed Questionnaire incorporates all the substantive content of the General Questionnaire, but in an expanded and more detailed format. It is structured as a guide or checklist for a longer interview that would be conducted by Dr. Clarke or a senior banking professional. There are far fewer occasions where responses are restricted to discrete choices. Rather, the respondent is encouraged to engage in a discussion of the issues raised.

To maintain our ability to conduct an interview whenever an appropriate contact is made, the follow-up calls to first tier institutions will be made by a senior professional or by Dr. Clarke. If later appointments are made, in-person or telephone interviews will be conducted by professionals capable of engaging the contact in extended discussion. This can draw out details and insights that a survey instrument or junior professional might not. In all cases, the survey questions will be adhered to. With all contacts, the first priority is to get a response to the questionnaire. Accordingly, if a contact expresses a strong preference responding via e-mail or printed form, we will accommodate the contact's wishes – including providing the Detailed Questionnaire in electronic or written form -- rather than reject any institution's participation. Needless to say, we will make every reasonable attempt to gain an interview with first tier contacts before retreating to this back-up procedure.

Contact Scripts

The purposes of a script are to increase the probability of full cooperation from the contacted financial institution and to provide a consistent point of reference for the persons making the contacts. The scripts incorporate a series of strategies to prompt the financial institutions' full participation. It follows opening salutations with a prominent mention of CARICOM, a "brand name" that should get the contact's attention and ease entry for the interviewer. It then "anchors" the respondent on the purposes and objectives of the survey – advising the contact of the scope of what is sought and fixing his or her attention on the pertinent portions of the banker's activities. The script then notes possible benefits of cooperation from the respondent's perspective, or the value placed on the respondent's expertise.

We have developed two scripts. One is for the follow-up calls promised in the first contact e-mail. This script guides the caller through the relatively simple process of arranging an interview appointment. However, it reminds the caller clearly that if the respondent is ready, the questionnaire interview must begin immediately.

The second script provides introductory remarks for the questionnaire interview. This script re-introduces CARICOM and the CREDP project and anchors the respondent on the survey topics and goals. The body of the questionnaire interview will be based on the questionnaire itself, instead of a script. The remarks can be used for either the General Questionnaire or the Detailed Questionnaire. Also provided is a Contact Sheet that reminds the interviewer that documentation of all contacts and the substance of all conversation and inquiries must be scrupulously recorded.

Questionnaires

As noted above, the General Questionnaire covers the basics of possible project financing arrangements – from demographics to loan processes to underwriting practices. The questionnaire is adequate to the task of guiding a junior professional through the process of collecting the data targeted in the questionnaire.

The Detailed Questionnaire surveys a wider range of topics and probes in greater depth. It addresses broad topics like the particulars of past loans and geographic areas of lending activity. It also probes into more technical matters, such as collateral and interest coverage ratios, credit spreads and loan syndications. In general, these issues are approached through open-ended questions designed to spur a dialogue between the interviewer and the financial institution contact. Accordingly, first tier financial institution interviews should be conducted by a senior professional. (Each survey incorporates both the first contact transmittal and the Term Sheet referenced in the questionnaire. Each also begins with a brief clarification of terms to facilitate clear communication during the interview.) As noted, each of the referenced survey instrument documents is included in Annex 1.

Since the survey process is continuing, a presentation of the lessons learned and (time permitting) revisions to our findings, recommendations, and templates are also unfinished. However, the report does incorporate the lessons one can reasonably draw from the preliminary and partial information collected to date.

Index of Report Attachments

- Survey Instruments (Questionnaires)
- Raw Survey Result Summaries/Report
- General Financing Recommendations??

Our analysis for off grid projects, like solar water heating facilities, was less extensive. Since the effects on the utility system of off-grid projects is indirect and more attenuated (basically demand reduction), analysis of the grid related issues is not necessary. And, though this element of the analyses has been much affected by the level of response from regional utilities, we have attempted to measure avoided energy and capacity costs for each of the seventeen (17) CARICOM member countries. For instances where that was not possible, we prepared a regional estimate of avoided costs, and identified utility cost drivers.

ADICA CONSULTING

ANNEX V

Resource Assessment Guidance

ADICA has reviewed the various resource assessment processes used for RET project in the course of its data gathering for its quantitative analyses. The specific economic effects with respect to different technologies are incorporated in the discussions of the analysis projects using those technologies. The specifics of required environmental assessments depend on the regulations in place at the project site. As to environmental effects, generally, the environmental benefits of using the output of RET projects reflect the displacement of a corresponding quantity of diesel generation – in particular, the elimination of CO_2 and other emissions associated with diesel generation.

The quantitative analyses performed revealed (and also demonstrate) the importance of good resource assessments for certain technologies. For example, because the output of wind turbine generators increases roughly with the cube of the wind speed, small differences in wind speed assumptions can have large effects on project output and economics. Similarly, in the case of run of river hydro, the resource assessment would detail the required river flow data and how the river flows can be converted to ranges of hourly, monthly and annual generation – providing reliability and dispatch information for the buyer, and projected revenue flows for the lender.

We recognize that specific real world environmental impact analyses and legal requirements will differ from country to country and for alternative technologies. For example, the environmental assessment for a wind farm could include site-specific issues like aspects of the towers, noise concerns, and problems associated with the construction of access roads or other infrastructure. Similarly, any general permitting approval descriptions are likely to be significantly affected by the laws and regulations of the host country. Preparing a specific guide for environmental assessments for each technology in each country would be costly and time consuming. Therefore, we have limited the task to a review of general environmental issues associated with each technology. In view of CARICOM's emphasis on the financial aspects of the development and commercialization process, we have limited the analysis by renewable experts so as avoid restating lessons CARICOM has learned from earlier CREDP studies.

Evaluation of Software Tools

In earlier CREDP phases the RETScreen model was used as a screening tool by CARICOM consultants. RETScreen was used primarily as a screening tool for wind power projects, although it was also used to evaluate at least one hydroelectric power project. ADICA reviewed the RETScreen screening model and the results of the model runs for the CARICOM pipeline RET projects. Although the output of the model was useful as a starting point in our analysis, the capabilities of the software tools developed as part of this consultancy -- and the regional specificity of the data out software utilizes -- make more detailed hourly avoided cost important.

In considering our recommendation, we evaluated the effect on project screening of the internalized wind speed data the RETScreen model uses. For example, the wind speed probability distributions use the Wiebull distribution, consistent with European wind speed studies. The wind characteristics in the Caribbean are significantly different. As a result of using the European data as a surrogate for local data, the advantages and benefits of wind projects are underestimated.

The particular distinctive features of the Caribbean wind profile are a higher average speed at the peak of the probabilistic distribution curve and a more normal distribution (as opposed to skewed toward lower speeds) of wind speeds. The effect of these differences is significant because for most wind turbine equipment, the power output of the equipment increases in relation to the cube of the change in wind speed. Consequently, (1) the higher speed of the most likely wind currents and (2) the normal distribution of all winds speeds over a higher speed range mean that the output of wind projects in the Caribbean will be greater than forecast by the RETScreen model. Increased output and increased revenues make Caribbean wind projects more economical than predicted by RETScreen.

The traditional screening process appears to be unnecessary for geothermal projects. There is usually little concern that the geothermal heat resource will be unavailable, as it might be with wind or seasonal hydro flows. The real question for the economics of a geothermal project is the cost of building the facility to achieve the needed output.[42] That cost is difficult to predict.

Capability Transfer

ADICA is prepared to further the CREDP objective of developing in-house and regional capabilities for conducting economic analyses independently in the future through an additional project activity that would provide training in conducting quantitative analyses like those we present in this report. The course would use the ADICA proprietary software that produced the quantitative analyses for this report. In this additional stage of

[42] The resource assessment (site assessment, including test drilling) for a potential geothermal project also can be an expensive process.

an extended consultancy, ADICA would organize training courses for regional professionals focused on conducting feasibility analyses of renewable projects in the region. Both CARICOM and CARILEC professionals, as well as other stakeholders, including utilities who have expressed interest in such training, could participate.

The course could use renewable projects in the CARICOM pipeline as instructional case studies. Such an instructional initiative could include generation planning and modeling, avoided costs analysis, benefit costs analysis, project finance modeling, structuring of project finance deals, and risk management issues. At the end of the course, participants would be able to complete an analysis for any of the member nations and for any type of renewable technology.

ANNEX VI

Glossary and Acronyms

Acronyms Used in the Report

- CARICOM – Caribbean Community Secretariat
- CARILEC – The Association of Caribbean Electric Utilities
- CDB – Caribbean Development Bank
- CEIS – Center for Environmental Information and Statistics
- CREDP – Caribbean Renewable Energy Development Programme
- IDC – Interest During Construction
- EPC – Engineering, Procurement and Construction Contract
- LOLP – Loss of load probability
- O&M – Operation & Maintenance
- PPA – Purchase Power Agreement
- RET – Renewable Energy Technology
- UWI-CED – University of the West Indies Centre for Environment and Development
- UWI-CERMES – University of the West Indies Centre for Resource Management and Environmental Studies

Terms Used in the Report

Before discussing the details of the rate impact analysis, we define some of the terms used in the analysis. Defining terms at the outset is presented to eliminate confusion as to the precise meanings of various concepts discussed in the body of the report:

<u>Avoided Cost:</u> This is a general concept that measures the reduction in costs that a utility company can experience if it purchases energy from a company that supplies renewable energy or if it develops energy projects.

<u>Avoided Fuel Cost:</u> The cost of the fuel a utility would need to generate the amount of energy being purchased from the renewable energy producer

<u>Avoided Variable O&M Cost:</u>

<u>Capacity Credits:</u> The percentage of capacity attributed to a renewable project for avoided capacity cost.

<u>Capacity Factor:</u>

<u>Construction Loan:</u> A loan that the covers the construction phase of a project (which may last from six months to a few years), where developers receive money on a monthly basis

(draws) to cover funding of equipment purchases and installation costs. The construction loan is repaid from a permanent loan when the project commences operation.

Emission Credits:

Environmental Externalities: The environmental effects of power plants that are not reflected in rates or cash flows.

Information Memorandum:

Loss of Load Probability:

Offering Circular:

Off-Taker: An electric utility purchaser

Operation & Maintenance Agreement:

Permanent Loan: A long-term loan that begins after the project begins commercial operation, and can have a tenor (the period before which the loan is fully repaid) of between 7 and 30 years. The permanent loan generally is **non-recourse** to the project sponsor, implying that only cash flows from the project are the re-payment source of the loan.

Project finance: A loan arrangement that is tied to a specific asset and supported by cash flow from a number of contracts, including a long term contract with a utility company, an operation and maintenance contract and a contract with a construction company to build a project.

Project Sponsor: The project sponsor is the project's equity investor and is generally the company that develops the project. If the project sponsor is not a utility company, the sponsor is known as a **non-utility developer**. For purposes of this questionnaire, the project sponsor is the party who is applying for the loan.

Purchased Power Agreement (PPA): contract between an electric utility purchaser (known as the off taker) and a company that constructs and operates a generation facility on an independent basis.

Required PPA Price: Price that must be paid by off-taker utility to the RET project (under the PPA) for the developer to achieve its IRR.